UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ______________**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED EMERGENCY OPERATIONS RELIABILITY STANDARDS

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<u>**TABLE OF CONTENTS**</u>

Exhibit A	Proposed Reliability Standards
	Exhibit A-1 Proposed Reliability Standard EOP-004-4
	Exhibit A-2 Proposed Reliability Standard EOP-005-3
	Exhibit A-3 Proposed Reliability Standard EOP-006-3
	Exhibit A-4 Proposed Reliability Standard EOP-008-2
Exhibit B	Implementation Plans
	Exhibit B-1 Implementation Plan for Proposed Reliability Standard EOP-004-4
	Exhibit B-2 Implementation Plan for Proposed Reliability Standards EOP-005-3, EOP-006-3 and EOP-008-2
Exhibit C	Order No. 672 Criteria
Exhibit D	Mapping Documents
	Exhibit D-1 Mapping Document for Proposed Reliability Standard EOP-004-4
	Exhibit D-2 Mapping Document for Proposed Reliability Standards EOP-005-3, EOP-006-3 and EOP-008-2
Exhibit E	Analysis of Violation Risk Factors and Violation Severity Levels
	Exhibit E-1 Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-004-4
	Exhibit E-2 Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-005-3
	Exhibit E-3 Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-006-3
	Exhibit E-4 Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-008-2
Exhibit F	Consideration of Issues and Directives
Exhibit G	Summary of Development History and Complete Record of Development
Exhibit H	Standards Drafting Team Roster

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Emergency Operations ("EOP") Reliability Standards EOP-004-4 (*Event Reporting*), EOP-005-3 (*System Restoration from Blackstart Resources*), EOP-006-3 (*System Restoration Coordination*), and EOP-008-2 (*Loss of Control Center Functionality*). NERC requests that the Commission approve the proposed Reliability Standards (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also proposes that the Commission approve: (i) the associated Implementation Plans (**Exhibit B**); (ii) the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit E**); and (iii) the retirement of the currently-effective Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2, and EOP-008-1, upon Commission approval of the proposed Reliability Standards.

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[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2016).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

As required by Section 39.5(a)[4] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[5] (**Exhibit C**), and a summary of the standard development proceedings (**Exhibit G**). The NERC Board of Trustees ("Board") adopted the proposed EOP Reliability Standards on February 9, 2017.

I. EXECUTIVE SUMMARY

The primary objectives of the proposed EOP Reliability Standards are as follows:

(1) to provide accurate reporting of events to NERC's Event Analysis group to analyze the impact on the reliability of the Bulk Electric System ("BES") (EOP-004-4);

(2) to delineate the roles and responsibilities of entities that support System restoration from Blackstart Resources which generate power without the support of the grid (EOP-005-3);

(3) to clarify the procedures and coordination requirements for Reliability Coordinator personnel to execute System restoration processes (EOP-006-3); and,

(4) to refine the required elements of an Operating Plan used to continue reliable operations of the BES in the event that primary control functionality is lost (EOP-008-2).

The proposed revisions incorporate several recommendations of the Project 2015-02 Emergency Operations Periodic Review Team as well as the Independent Experts Review Panel ("Panel").[6] They also reflect collaboration with the Department of Energy ("DOE") to eliminate

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4 18 C.F.R. § 39.5(a)(2016).

5 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* ("Order No.672"), Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

6 NERC retained five industry experts ("Panel") to independently review the content and quality of the NERC Reliability Standards, including identification of potential BPS risks that were not adequately mitigated. *See* Standards Independent Experts Review Project: An Independent Review by Industry Experts, *available at* http://www.nerc.com/pa/Stand/Resources/Documents/Standards_Independent_Experts_Review_Project_Report.pdf.

either inaccurate or duplicate reporting of events identified in DOE's Electric Emergency Incident and Disturbance Report ("OE-417") as well as in Attachment 1 to NERC's Reliability Standard EOP-004. The proposed standards substantially improve upon the existing standards by enhancing the requirements for Emergency operations, including the communication and coordination amongst reporting entities.

For reasons discussed herein, NERC requests that the Commission approve the proposed Reliability Standards and the proposed retirement of Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2 and EOP-008-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the nation's Bulk-Power System,

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[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2012), to allow the inclusion of more than two persons on the service list in this proceeding.

[8] 16 U.S.C. § 824o (2012).

and with the duties of certifying an Electric Reliability Organization (ERO) that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[9] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[10] Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.[11]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c) of the Commission's regulations, "the Commission will give due weight to the technical expertise of the ERO" with respect to the content of a Reliability Standard.[13]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14] NERC

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9 *Id*. at § 824(b)(1).

10 *Id*. at § 824o(d)(5).

11 18 C.F.R. § 39.5(a)(2016).

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1)(2016).

14 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering

develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15] In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[16] and thus satisfy certain of the criteria for approving Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. Development of the Proposed Reliability Standards

As further described in **Exhibit G** hereto, the proposed Emergency Preparedness and Operations ("EOP") group of Reliability Standards (EOP-004-4, EOP-005-3, EOP-006-3, and EOP-008-2) were developed to implement the revisions and retirements recommended by the EOP Standard Drafting Team from Project 2015-02 – Periodic Review of Emergency Operations ("EOP SDT"). In addition, the proposed EOP Reliability Standards are intended to (1) streamline the

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whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

[15] The NERC *Rules of Procedure*, *available at* http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual, available at* http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[16] *N. Am. Elec. Reliability Corp,* 116 FERC ¶ 61,062, at P 250.

[17] Order No. 672, at PP 268, 270.

standards; (2) apply Paragraph 81 criteria;[18] while making the standards more results-based; and (3) address the Commission's concern articulated in Order No. 749 regarding system restoration training.[19]

For a summary of the development history in Project 2015-08 and the complete record of development, see **Exhibit G**.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in **Exhibit C**, the proposed Reliability Standards satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Below, NERC (1) describes the reliability purpose of each proposed standard, (2) provides a justification for the proposed revisions to each Reliability Standard, and, (3) discusses the enforceability of the proposed standards.

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[18] *See* North American Electric Reliability Corp., 138 FERC ¶ 61,193, at P 81 (March 2012 Order), order on reh'g and clarification, 139 FERC ¶ 61,168 (2012).

[19] Order No. 749, *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, 76 Fed. Reg. 16277 (2011) ("Order No. 749") at PP 18, 24:

> Requirement R11 of EOP-005-2 requires that a minimum of two hours of system restoration training be provided every two years to field switching personnel performing "unique tasks" associated with the transmission operator's restoration plan. In the NOPR, the Commission expressed concern that the applicable entities may not understand what the term "unique tasks" means. We requested comment on what is intended by that term and on whether guidance should be provided to the transmission operators, transmission owners, and distribution providers who are responsible for providing training. In addition, the NOPR sought comment as to whether the unique tasks should be identified in each transmission operator's restoration plan.
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> . . .
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> Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations.

A. Proposed Reliability Standard EOP-004-4 – Event Reporting

The purpose of Reliability Standard EOP-004-4 is to improve the reliability of the BES by requiring the reporting of events by Responsible Entities. The reportable events under this standard are collected and used for operations planning and operational assessments. Specifically, these reportable events are used to examine the underlying causes of events, track subsequent corrective action to prevent recurrence of such events, and develop lessons learned for industry. The reportable events under this standard are not intended to address issues that arise in Real-time operations which often require action by Responsible Entities within one hour or less to preserve the reliability of the BES.

The proposed changes to this standard are designed to (1) eliminate redundant reporting of a single event by multiple entities, (2) assign reporting to appropriate entities, (3) clarify the threshold reporting for a given event; and, (4) where appropriate, align the reportable events and thresholds identified in Attachments 1 and 2 of the standard with the DOE's OE-417. The proposed changes improve the quality of information received by the ERO as well as the quality of analysis that the ERO produces from this information to assess the greatest risk to the BES.

1. Requirement-by-Requirement Justification

a. EOP-004-4, Proposed Requirement R2

In Requirement R2, NERC proposes to expressly reference Attachment 1. This reference was previously absent from Requirement R2 and improves the requirement by identifying the universe of events reportable under this standard. NERC also streamlines the timing language for event reporting. NERC proposes that Responsible Entities must submit reports "by the later of" either 24 hours after recognizing that a reportable event has occurred or "by the end of the Responsible Entity's next business day." The EOP SDT found that referencing "business day" eliminates the need for the requirement to further indicate that reporting is not expected on the weekend and holidays. The EOP SDT denotes the end of the business day as "4 p.m. local time" to eliminate possible confusion regarding when the reporting obligation ends on a given business day. None of these changes, as reproduced below, affect the frequency or pace at which EOP-004 reports are submitted.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan ~~within~~ by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM~~ (4 p.m. local time ~~on Friday to 8 AM Monday local time).~~will be considered the end of the business day). [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

b. EOP-004-4, Proposed Retirement of Requirement R3

Under the currently-effective Requirement R3, Responsible Entities must validate contact information in their Operating Plans each calendar year. NERC proposes to retire Requirement R3 under Criterion B1 as an administrative task not warranting a requirement.[20] The process of validating contact lists is a good business practice of many utilities, but not a reliability priority. Furthermore, this proposed retirement of Requirement R3 is also consistent with the Panel's recommendation and rationale.

[20] Paragraph 81 Criteria B (Identifying Criteria) - B1. Administrative:
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

c. EOP-004 - Attachment 1: Reportable Events

In Attachment 1 NERC identifies the types and thresholds of reportable events that have the potential to impact the reliability of the BES. To report events to NERC, Responsible Entities in the U.S. must submit Attachment 2 to EOP-004, which incorporates the event types in Attachment 1. To the extent that DOE's OE-417 reflects similar event types and thresholds as Attachment 2, Responsible Entities in the U.S. may submit OE-417 in lieu of Attachment 2.

The currently-effective event types and thresholds reflected in Attachments 1 and 2 and OE-417 are not all aligned, resulting in a level of uncertainty as to whether an event is reportable. Some event types overlap (e.g., "system wide voltage reduction of 3% or more" in EOP-004 and "system-wide voltage reductions of 3 percent or more" in OE-417). In other event types, the degree of overlap is ambiguous (e.g., "physical threat to its BES control center.. .which has the potential to degrade the normal operation of the control center or suspicious device or activity at a BES control center" in EOP-004 compared to "physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems" in OE-417). Certain event types exist exclusively in EOP-004 (e.g., "complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement"). In cases where a Responsible Entity is unsure whether two event types are aligned between the two forms, that entity could duplicate efforts and submit both forms for a single event. Alternatively, a Responsible Entity may fail to report a reportable event due to ambiguity in the description of an event type in either form.

The accurate reporting of disturbances and events is essential for the ERO and governmental authorities, such as DOE, to provide industry with meaningful trend and root causes analyses. The EOP SDT identified the potential for efficiency in clarifying event types and thresholds and aligning reporting requirements between EOP-004 and OE-417.[21] The proposed revisions to Attachment 1 represent an improvement in the identification and reporting of such events.

NERC's proposed revisions to Attachment 1 aim to accomplish the following:

(1) assign reporting to responsible entities with relevant operating responsibilities;

(2) align the event types between Attachment 1 and OE-417 as much as possible to eliminate redundancies in reporting of a single event thereby enhancing the efficiency of event reporting; and,

(3) establish appropriate thresholds for triggering events that pose the greatest reliability risk to the BES.

Below, NERC outlines the proposed revisions to each event type and its respective threshold.

i. Damage or Destruction to Facilities

Responsible Entities that experience damage or destruction to a Facility resulting from "actual or suspected intentional human action" are required to submit a report to NERC. NERC proposes three changes to this event type. First, NERC proposes to remove Balancing Authorities as Responsible Entities, but leaves Transmission Owners, Transmission Operators, Generation Owners, Generation Operators, and Distribution Providers as appropriate Responsible Entities. The EOP SDT found that Facility owners and operators are best suited to identify any damage or destruction to their Facilities and therefore should bear the reporting responsibility. Examples of Facilities include a Transmission line, a generator, a shunt compensation device or a transformer. Balancing Authorities do not own the relevant Facilities. To further reflect the importance of

21 The ERO has an Event Analysis Program ("EAP") which evaluates the reports submitted pursuant to EOP-004 and OE-417. Such reports may trigger further scrutiny by EAP personnel. EAP personnel may request that more data about a given event.

ownership or operations of a Facility to identification of such an event, NERC also proposes to change the event type from "Damage or destruction of a Facility" to "Damage or destruction of its Facility." Finally, NERC clarifies in the event threshold that theft from its Facility should not be reported as damage or destruction unless it degrades normal operation of its Facility. Copper theft from the infrastructure of Facilities is a frequent occurrence in the industry; however, the EOP SDT concluded that the reporting obligation for this event type should focus on those that threaten the operation of the Facility. Acts of theft were previously reported under the "physical threat" event type and NERC proposes to move it to the "damage or destruction" event type because it involves the infrastructure of a Facility.

ii. Physical Threats to Facilities

Responsible Entities that experience physical threats to a Facility, including suspicious devices or activities at a Facility, but excluding weather and natural disaster, are required to submit an event report. NERC proposes three changes to this event type. NERC again proposes that Facility owners and operators are best suited to identify any such threat and therefore should bear the reporting responsibility. As a functional entity, Balancing Authorities do not own or operate a Facility; therefore, they are removed as a Responsible Entity. Second, to reflect the importance of ownership or operation of a Facility, NERC proposes to change the event type to "Physical threats to its Facility." Finally, NERC proposes to modify the statement "Do not report theft unless it degrades normal operation of a Facility" and to modify it to read as "It is not necessary to report theft unless it degrades normal operation of its Facility." NERC also moves this modified language to the "Damage or Destruction of its Facility" threshold for reporting. An actual act of theft to a Facility more closely relates to damage or destruction of a Facility rather than a physical threat.

iii. Physical Threats to BES Control Center

Consistent with other event types, NERC proposes to change the physical threat event type and threshold to reflect the importance of ownership of a Facility. NERC proposes to change the event type to "Physical threats to its BES control center" and the threshold to "Suspicious device or activity at its BES control center."

iv. Public Appeal for Load Reduction

NERC Reliability Standard EOP-011-1 (Emergency Operations) ensures that all Reliability Coordinators understand potential and actual Energy Emergencies in the Interconnection. Energy Emergency Alert Level 2 (EEA-2) involves load management procedures such as public appeals to reduce demand, interrupting firm load commitments, and voltage reduction. Public appeals for load reduction are conducted when load is expected to exceed available generation. Such appeals often occur on extreme weather days where a local utility asks customers to reduce usage of electricity during certain hours of the day. These appeals would not include load management for economic reasons.

NERC proposes two substantive changes to the "public appeal for load reduction" event type in EOP-004-4 to report instances where an entity initiates a public appeal for load reduction. First, NERC replaces "initiating entity" with "Balancing Authority" as the entity responsible for reporting this event. Pursuant to EOP-011-1 (Emergency Operations), it is the Balancing Authority that develops, maintains and implements Reliability Coordinator-reviewed Operating Plans to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. Balancing Authorities must include processes to prepare for and mitigate Emergencies in these Operating Plans. Furthermore, the Balancing Authority, pursuant to Reliability Standard EOP-011-1, Requirement R2, Part 2.2.2, is responsible for requesting the Reliability Coordinator to declare an Energy Emergency Alert. Second, NERC clarifies that the threshold for such a load reduction event is when the requested reduction is required to maintain the continuity of the BES. This clarifying language aligns with similar language in DOE's OE-417 form which includes the event type "Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system."

v. Voltage Reduction

Voltage reduction is a load management procedure in which the Transmission Operator requests or directs distribution operators to decrease voltage in the distribution portion of the System to minimize the likelihood of service interruptions. This lower voltage in turn reduces the load on home devices. For purposes of reporting voltage reduction under EOP-004-4, NERC replaces the phrase "initiating entity" with "Transmission Operator" as the Transmission Operator is in fact the entity that initiates voltage reduction and, in turn, should be responsible for reporting the event.

vi. Load Shedding

NERC proposes to combine two event types – "BES Emergency requiring manual firm load shedding" and "BES Emergency resulting in automatic firm load shedding" into a single event type – "Firm load shedding resulting from a BES Emergency." This change streamlines the list of events in Attachment 1. In the reporting threshold, NERC indicates that the 100 MWs threshold can be attributed to either manual or automatic load shedding. NERC also removes the requirement that the automatic load shedding be attributed to "undervoltage or underfrequency load shedding schemes, or [Remedial Action Schemes]." These schemes are automatic systems designed to decrease load when either the voltage or frequency of a System reaches predetermined low levels. The EOP SDT found that it was unnecessary to detail specific types of load shedding schemes in the standard. As the name of a scheme may change and new load shedding practices may be developed, NERC proposes to keep the language in the threshold broad and to eliminate specific practice references to accommodate future changes in practice or nomenclature.

For both automatic and manual load shedding, NERC identifies the Responsible Entity as the "initiating Reliability Coordinator, Balancing Authority or Transmission Operator." Pursuant to EOP-011-1 (Emergency Operations), Balancing Authorities and Transmission Operators must develop, maintain and implement Reliability Coordinator-approved Operating Plans to mitigate Capacity Emergencies, Energy Emergencies, and operating Emergencies in their respective areas. These Operating Plans shall include provisions for operator-controlled manual Load shedding that minimize the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency. NERC recognizes that for a given event, a single entity may be registered for all three functions or three separate entities may be registered for each of these functions. It is the intent of the EOP SDT that in either scenario, only one report is required.

Distribution Providers and Transmission Operators were previously listed as entities with reporting responsibility for automatic firm load shedding. NERC proposes to remove Distribution Providers and instead assign the reporting obligation to the "initiating Reliability Coordinator, Balancing Authority or Transmission Operator" because these entities have the appropriate level of visibility to make assessments of the condition of the System. Any one of these functions can independently generate or issue an Operating Instruction to shed firm load, but the Distribution Provider cannot do so. Reliability Standard TOP-001-3 (Transmission Operations), Requirements R1 and R2 provide that each Transmission Operator and Balancing Authority shall act to maintain the reliability of its Transmission Operator Area and Balancing Authority Area via its own actions or by issuing Operating Instructions. Requirements R3 and R5 further provide that the Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator (s) or Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Furthermore, the purpose of Reliability Standard EOP-011-1 (Emergency Operations) is to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Areas. Requirements R1 and R2 apply to the Transmission Operator and Balancing Authority, but not to the Distribution Provider.

vii. Voltage Deviation

A voltage deviation is the difference, generally expressed as a percentage, between the voltage at a given instant at a point in the system, and a reference voltage (i.e., nominal voltage, a mean value of the operating voltage, or declared supply voltage). NERC proposes to clarify the event type name and threshold. NERC references "BES Emergency" in the event type to align with other event types in Attachment 1 that warrant an action to preserve the reliability of the BES, not a localized event. In the event threshold, NERC clarifies the range of deviation that threatens the reliability of the System. In the currently-effective standard, the identified range of "± 10%" could be interpreted as not requiring an event report if the voltage deviates more than 10%. Therefore, NERC proposes that the relevant deviations warranting a report are those high, positive deviations that exceed or are equal to 10% of the nominal voltage.

viii. IROL Violation

Under the currently-effective standard, Reliability Coordinators are required to report when they are operating outside of their Interconnection Reliability Operating Limit ("IROL"). Specifically, an IROL violation occurs when the Transmission Operator operates outside the IROL for a specified time known as IROL Tv. An IROL is a System Operating Limit,[22] which if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES. NERC proposes to retire the IROL violation event type under EOP-004-4 because EOP-004 is not designed to be a Real-time tool. During development of proposed Reliability Standard EOP-004-4, some stakeholders commented that the removal of the IROL event type deprives NERC and the Regional Entities of immediate or contemporaneous knowledge of a risk of a cascading outage, thereby preventing a Regional Entity from immediately identifying the root cause and developing appropriate mitigation. The EOP SDT found that any Real-time reporting to the ERO or the Regional Entities (i.e., contemporaneously with the Transmission Operator's notification of the IROL to the Reliability Coordinator) should be addressed in the TOP Reliability Standards which deal with the Real-time operations time horizon. In contrast, proposed EOP-004-4 is primarily a tool for trending analysis and development of lessons learned.

The EOP SDT found that Reliability Standard TOP-001-3 (Transmission Operations) is the appropriate standard for reporting such events. The purpose of Reliability Standard TOP-001-3 is to prevent instability, uncontrolled separation, or Cascading outages, in Real-time, that adversely impact the reliability of an Interconnection by ensuring "*prompt action to prevent or mitigate such occurrences*." Specifically, Requirement R12 states that "[e]ach Transmission

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22 A "System Operating Limit" or "SOL" is the value that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated Tv." Requirement R2 of Reliability Standard TOP-007-0 (Reporting SOL and IROL Violations) states that "[f]ollowing 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." Finally, Requirement R3 of Reliability Standard IRO-009-2 (Reliability Coordinator Actions to Operate within IROLs) states that "[e]ach Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment."

ix. Loss of Firm Load

Under the currently-effective standard, Balancing Authorities, Transmission Operators and Distribution Providers are required to report two types of incidents involving loss of firm load lasting at least 15 minutes: (1) loss of firm load greater than or equal to 300 MWs for those entities whose previous year's demand was greater than or equal to 3,000 MWs, or, (2) loss of firm load greater than or equal to 200 MWs for all other entities. NERC proposes to rename the event type to include "resulting from a BES Emergency" to align with other event types in Attachment 1 that use this language.

NERC also proposes three changes to the event threshold to capture reporting of loss of firm load events that pose the greatest risk to the reliability of the BES. First, NERC specifies that reporting must occur for "*uncontrolled* loss of firm load" to eliminate reporting of intentional acts by operators choosing to shed load to maintain System stability. This language aligns with the event type language in OE-417. Second, NERC underscores that the load loss specifications in this event type pertain to "a single incident" and should be reported only once by either the

Balancing Authority, Transmission Operator, or Distribution Provider, not all three. Finally, NERC notes that for entities that suffer uncontrolled loss of firm load equal to or exceeding 300 MWs, the threshold for reporting entities is the previous year's "peak" demand $\geq$ 3,000 MWs. By highlighting "peak" demand, the EOP SDT notes that this improves the quality of reports by focusing on the period posing the greatest risk to reliability.

x. Generation Loss

Under the currently-effective "Generation loss" event type, Balancing Authorities and Generator Operators must report total generation loss occurring within one minute that is either greater than or equal to 2,000 MWs (for entities in the Eastern or Western Interconnection) or greater than or equal to 1,000 MWs (for entities in the ERCOT or Quebec Interconnection). NERC proposes four changes to the generation loss event type.

First, NERC proposes to remove "Generator Operators" as a reporting entity to eliminate redundant reporting with Balancing Authorities for this event type. The EOP SDT found that the obligation to report generation loss should rest solely with the Balancing Authority which has a broader view of the system. It is the role of the Balancing Authority to maintain the generation-load-interchange balance within its entire Balancing Authority Area.

Second, NERC proposes to raise the reporting threshold for generation loss in the Quebec Interconnection from 1,000 MWs to 2,000 MWs. Generation in the Québec Interconnection is 95 % hydraulic. For efficiency reasons, generation must operate within 80 % of its operating range; therefore, there is a large spinning operating reserve available at all times. This large spinning reserve aids in the recovery period following an event. Generation is often adjusted in a Balancing Authority Area to maintain the Area Control Error or "ACE" around zero. ACE is the instantaneous difference between a Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. In Quebec, the recorded average ACE recovery time for a 2,000 MWs generation loss is 5 minutes which is three times faster than the required recovery time of 15 minutes pursuant to Reliability Standard BAL-002-1a, Requirement R4.2 (Disturbance Control Performance).[23] Following a review of Under Frequency Load Shedding events since 2000 submitted by Hydro Quebec, the EOP SDT found that generation loss between 1,500 MWs and 2,000 MWs has not triggered the first stage threshold of the Under Frequency Load Shedding ("UFLS") scheme. The fact that no recent events have triggered activation of UFLS is significant. Activation of UFLS represents the last automated reliability measure associated with a decline in frequency needed to rebalance the System. UFLS is intended to be a safety net to prevent against System collapse for severe contingencies. Finally, Quebec has set 2,000 MWs as the threshold for generation loss that would warrant a deficient Balancing Authority to request its Reliability Coordinator to declare an Energy Emergency Alert ("EEA"). EEAs are emergency procedures implemented if unusually high electricity demand or an unexpected loss of generation. The EOP SDT reviewed historical EEA Level 3 alerts for the last 14 years (2000 through 2014) and found no EEA level 3 alerts have occurred during this period in the Quebec Interconnection. Under Quebec's contingency analysis to evaluate abnormal conditions in its electrical network, it has set 2,000 MWs as its loss of generation threshold in the first or primary contingency.

Third, NERC proposes to raise the generation loss reporting threshold for the ERCOT Interconnection from 1,000 MWs to 1,400 MWs. NERC notes that this is a lower threshold than the 2,000 MWs threshold for ERCOT pursuant to the ERO event analysis process. ERCOT

[23] Reliability Standard BAL-002-1a is designed to help Balancing Authorities utilize Contingency Reserves to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

maintains a mix of operating reserves to aid in the recovery period following an event affecting ACE or frequency. This mix comprises of 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves. ERCOT procures between 2,300 MWs and 3,000 MWs of frequency response reserves for all operating hours in addition to procuring additional regulation and non-spinning reserves. The Load Resources are set to respond automatically at 59.7 Hz to provide instantaneous frequency response. The EOP SDT also identified the recorded average ACE recovery time for a 1,400 MWs loss as 10 minutes for the period between December 2014 and November 2016, which is faster than the required 15 minutes pursuant to BAL-002-1a, Requirement R4.2 (Disturbance Control Performance). ERCOT's frequency responsive reserves are set at a level to allow ERCOT to keep frequency above the under-frequency limit up to ERCOT's resource contingency protection criteria limit of 2,750 MWs. This limit, which is almost double the proposed threshold, is significant because it represents the point at which frequency response should be adequate to avoid violating UFLS settings. This limit is also based on the most severe double contingency in ERCOT. Finally, the proposed 1,400 MWs threshold is below the currently-effective EEA level 1 alert, the lowest EEA level in ERCOT, which is set at 2,300 MWs.

Finally, NERC proposes to clarify the scope of reportable generation loss. Specifically, NERC notes that reportable generation loss covers that resulting from the removal from service availability of a generating unit for emergency reasons and the condition of the unavailable equipment due to unanticipated failure (i.e., Forced Outage). It is not intended to cover generation loss associated with weather patterns or fuel supply unavailability for dispersed power producing resources. The variable output of these sources is understood by the Reliability Coordinator, Balancing Authority, and Transmission Operator entities. Balancing Authorities responsible for balancing load and generation model these generation resources accounting for this inherent variability.

xi. Transmission Loss

Under the currently-effective standard, Transmission Operators must report unexpected transmission loss within its area if the loss occurs (1) following a common disturbance, (2) in a manner that is contrary to design or unintended, and (3) involving three of more BES Elements. For this "transmission loss" event type, NERC proposes to replace "BES Elements" with "BES Facilities" in the event threshold description to capture transmission loss events that pose the greatest risk to the reliability of the BES. The EOP SDT found that an unexpected loss of three or more BES Elements is too granular and captures three or more individual device or equipment failures (i.e., circuit breakers, disconnects, capacitor banks, reactors, bus potential devices) that are unlikely to cause a common disturbance. The EOP SDT determined that the focus should be on Facilities that cease to provide a path for BES power flows. This is also consistent with the approach taken in the ERO event analysis process.

xii. Complete Loss of Communication

NERC proposes to change the "complete loss of voice communication capability" event type to "complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center" to account for the variety of media used by operators today consistent with Reliability Standard COM-001-2 (Communications). The purpose of COM-001-2 is to establish Interpersonal Communication capabilities necessary to maintain reliability. The communication capabilities used by Reliability Coordinators, Transmission Operators and Balancing Authorities may not necessarily be using the same medium. In Order No. 808, the Commission approved two new communication definitions that NERC proposes to incorporate into this event type – "Interpersonal Communication" defined as "any medium that allows two or more individuals to interact, consult, or exchange information," and, "Alternative Interpersonal Communication" defined as "any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."[24] These expanded definitions of Communication capture more than just voice communication capability and more closely align with practices of the reporting entities.

NERC also proposes to specify that the loss of communication threshold pertains to the reporting entities' at its "staffed BES control centers." The EOP SDT found that unless a control center is staffed, the Responsible Entity could not be made aware of an issue. Since a greater number of media are accommodated by the proposed changes, NERC does not expect to see any decrease in reporting for this revised event.

xiii. Complete Loss of Monitoring Capability

NERC proposes to amend and streamline the monitoring capability event type and threshold as follows:

- Event Type - "Complete loss of monitoring or control capability at its staffed BES control center"
- Threshold for Reporting - "Complete loss of monitoring or control capability ~~affecting~~ ~~a~~ at its staffed BES control center for 30 continuous minutes or more ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable~~."

[24] Order No. 808, *Communications Reliability Standards*, 151 FERC ¶ 61,039, 80 Fed. Reg.22, 385 (2015) at fn. 54*; Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards COM-001-2 and COM-002-4*, Docket No. RM14-13-000 (filed May 14, 2014) at 18.

NERC proposes that the addition of "control capability" in both the event type and threshold adequately addresses the phrase "such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable." NERC also specifies that loss of this capability pertains to reporting entities with "a staffed BES control center." The EOP SDT found that unless a control center is staffed, the Responsible Entity would not be aware of an issue.

d. EOP-004 - Attachment 2: Event Reporting Form

NERC has collaborated with DOE to align the event types and reporting thresholds between EOP-004 and DOE's OE-417 report for U.S. entities. Under current practice, the ERO will accept DOE's OE-417 report in lieu of Attachment 2 to the extent a given event type and threshold align. The proposed event type changes to Attachment 1, as discussed above, are also reflected in Attachment 2. In addition, NERC clarifies in the instructions to Attachment 2 that EOP-004-4, Requirement R1 requires submission of either Attachment 2 or the OE-417 report to other applicable organizations outside of the ERO (i.e., the entity's Regional Entity, company personnel, the entity's Reliability Coordinator, law enforcement or other Applicable Governmental Authorities).

B. Proposed Reliability Standard EOP-005-3 – System Restoration from Blackstart Resources

The purpose of proposed Reliability Standard EOP-005-3 is to "[e]nsure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Proposed Reliability Standard EOP-005-3 improves the existing version of the standard in three ways:

(1) emphasizes the need for Transmission Operators to not only develop, but utilize restoration plans relating to Blackstart Resources;

(2) streamlines the standard and retires redundant or administrative requirements; and

(3) clarifies requirements for revising and testing restoration plans.

Additionally, NERC proposes to retire existing Reliability Standard EOP-005-2, as described in the Implementation Plan for EOP-005-3 (**See Exhibit B-1**) to ensure a seamless transition to the newly revised standard.

1. Requirement-by-Requirement Justification

a. EOP-005-3, Proposed Requirement R1

Requirement R1 has been revised as follows:

R1. Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~ be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~ shutdown area ~~to service~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1 Strategies for ~~s~~System restoration that are coordinated with ~~the~~ its Reliability Coordinator's high level strategy for restoring the Interconnection.

. . .

1.3 Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~ its Reliability Coordinator.

. . .

1.9 Operating Processes for transferring ~~authority~~ operations back to the Balancing Authority in accordance with ~~the~~ its Reliability Coordinator's criteria

NERC proposes the addition of "develop and implement" to replace "have" as well as the addition of "be implemented to restore" to replace "allow for restoring" to emphasize the need for the Transmission Operator to not only possess, but to utilize its restoration plan for Real-time operations in the event of a Disturbance. The addition of the word "implement" requires the addition of "Real-time Operations" to the Time Horizon of this requirement. The addition of "implement" to Requirement R1 makes Requirement R7 redundant. Requirement R7 provides that:

> R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration.

As a result of this redundancy, NERC proposes to retire Requirement R7. This proposed retirement is consistent with the recommendation of the Panel to retire Requirement R7 as redundant with Requirement R1. In describing the use of Blackstart Resources to restore the shutdown area, NERC proposes to delete the words "to service" in Requirement R1 as redundant with the ensuing language calling for "restoration of a shutdown area to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System."

With respect to Requirement R1, Parts 1.1, 1.3 and 1.9, NERC proposes to replace "the Reliability Coordinator" with "its Reliability Coordinator" to clarify that strategies, procedures and operating processes for restoring interconnections and System restoration require coordination with the Reliability Coordinator in the footprint where the Transmission Operator is located.

With respect to Requirement R1, Part 1.9, NERC proposes to replace "authority" with "operations" to clarify two points. First, the EOP SDT noted that while the Transmission Operator is responsible for developing and implementing the restoration plan, the Transmission Operator does not assume any authority from the Balancing Authority. During restoration, the Transmission Operator dedicates its resources to rebuilding its System. Second, the requirement to include operating processes in a restoration plan relates to the role of the Reliability Coordinator. During restoration, the Reliability Coordinator maintains its wide area view of the System. The Reliability Coordinator takes operational authority and gives different entities assigned tasks until they are ready to resume normal operation. As restoration progresses, the Reliability Coordinator gradually transfers operations back to the appropriate entities.

b. EOP-005-3, Proposed Requirement R2

The EOP SDT replaces "implementation date" with "effective date" to clarify that the "implementation date" refers to any given use of a plan. Therefore, a given plan could have several implementation dates. "Effective date" more accurately represents the pertinent date when entities identified in a restoration plan should have a copy of a restoration plan changing roles and tasks for future implementation. Recognizing that the Reliability Coordinator has 30 days under EOP-006 to render a decision on restoration plan revisions, Transmission Operators must determine the appropriate effective date for their plans. They must take into account the potential for unknown factors (i.e., weather, system operational needs) to affect the configurations in their plans and the subsequent in-service dates.

Requirement R2 has been revised as follows:

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning**]**

c. EOP-005-3, Proposed Requirement R3

Requirement R3, Part 3.1, was retired by the Commission in Order No. 788.[25] NERC is not proposing any further revisions to Requirement R3 in this petition.

d. EOP-005-3, Proposed Requirement R4

In the *Report on the FERC-NERC Regional Entity Joint Review of Restoration and Recovery Plans* ("Joint FERC-NERC Report"),[26] joint staff from NERC and FERC recommended that NERC clarify when system changes trigger a requirement to update restoration plans. The joint staff recommended that NERC examine:

> [1] the kinds of events that may warrant an update to the system restoration plan . . . taking into account the length of time the system is affected (*not just permanent or planned system modifications*), as well as [2] the overall objective of ensuring that restoration plans are generally flexible enough so that system modifications can be addressed without continuous updates. [Emphasis added]

With this guidance, NERC proposes two event types of restoration plan revisions warranting submission to its Reliability Coordinator: (i) unplanned permanent BES modifications and (ii) planned, permanent BES modifications. NERC also proposes that for the former, Transmission Operators submit revised restoration plans within 90 calendar days after identifying the modification. For the latter type, NERC proposes that Transmission Operators submit revised restoration plans in time to meet its Reliability Coordinator's approval timeframe per EOP-006, which is no less than 30 calendar days after identifying the modification. Proposed Requirement R4 provides as follows:

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[25] Order No. 788, *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147, 78 Fed. Reg. 73424 (2013).

[26] *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans* ("FERC-NERC Joint Report"), (Mar. 20, 2017), *available at* https://www.ferc.gov/legal/staff-reports/2016/01-29-16-FERC-NERC-Report.pdf.

R4. Each Transmission Operator shall ~~update~~ submit its revised restoration plan to its Reliability Coordinator for approval ~~within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan~~ when the revision would change its ability to implement its restoration plan as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. ~~Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same~~ Within 90 calendar ~~day period~~ days after identifying any unplanned permanent BES modifications; and~~.~~

~~4.1.~~4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

Detailed below is an additional discussion of the modifications in Requirement R4.

A. BES Modifications vs. System Modifications

The currently-effective standard references both "unplanned permanent System modifications" and "planned BES modifications" as two event types requiring updates to a restoration plan. NERC proposes the consistent use of "BES modifications" in lieu of "System modifications." The term "BES" was developed through the NERC Standards Development Process and is included in the *Glossary of Terms Used in NERC Reliability Standards*.[27] The use of the phrase "BES modifications" is intended to capture changes that affect the implementation of a restoration plan. Administrative changes, such as element number changes and device changes, are examples that would not have a significant impact on the implementation of a restoration plan and that would not be considered BES modifications.

B. Duration of a BES Modification

NERC proposes that the "permanence" of BES modifications is an important threshold to determine when to submit revisions to a restoration plan. In the FERC-NERC report, staff

[27] Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* http://www.nerc.com/files/glossary_of_terms.pdf.

encouraged NERC to examine the length of time the system is affected. NERC maintains that the "permanence" of a BES modification is a relevant threshold, regardless of whether planned or unplanned. Using the "permanence" of a BES modification as a threshold is necessary to avoid updates due to temporary configurations required to support maintenance and construction. It also underscores that Transmission Operators should only submit changes that substantively affect the implementation of their restoration plans.

C. Timing of Updates to Restoration Plans

In the FERC-NERC Joint Report, staff recommended that NERC clarify when System changes under Requirement R4 will trigger a requirement to update restoration plans.[28] In the currently-effective standard, it is unclear whether the 90 calendar day timeframe for updating restoration plans applies to both "unplanned permanent System modifications" and "planned BES modifications." NERC proposes two different triggers for submitting restoration plans to Reliability Coordinators for "unplanned permanent BES modifications" and for "planned permanent BES modifications." Unplanned permanent BES modifications should be submitted to the Reliability Coordinator no more than 90 calendar days after identifying the need for an unplanned, permanent BES modification. Planned, permanent BES modifications should be submitted to the Reliability Coordinator in accordance with EOP-006 Requirement R5, Part5.1. EOP-006 Requirement R5, Part 5.1 provides that the Reliability Coordinator shall approve or disapprove a submitted restoration plan within 30 days of receipt. Therefore, planned, permanent BES modifications should be submitted to the Reliability Coordinator no less than 30 calendar days prior to implementation in order to afford the Reliability Coordinator the minimum required

28 FERC-NERC Joint Report at 37.

time to render a decision under EOP-006, Requirement 5, Part 5.1. Proposed Reliability Standard EOP-005, Requirement 4, Parts 4.1 and 4.2, are revised as follows:

R4. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval ~~within the same 90 calendar day period~~, when the revision would change its ability to implement its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

e. EOP-005-3, Proposed Requirement R5

Consistent with Requirement R2, "implementation date" was revised to "effective date." "Effective date" more accurately represents the pertinent date when entities identified in a restoration plan should have a copy of a restoration plan changing roles and tasks for future implementation. Recognizing that the Reliability Coordinator has 30 days under EOP-006 to render a decision on restoration plan revisions, Transmission Operators must determine the appropriate effective date for their plans. Requirement R5 has been revised as follows:

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its ~~implementation~~ effective date.

f. EOP-005-3, Proposed Requirement R6

NERC proposes to clarify the methodology and frequency of required testing of restoration plans in Requirement R6, as follows:

R6. Each Transmission Operator shall verify through analysis of actual events a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years ~~at a minimum~~. Such analysis, simulations or testing shall verify. . .

Industry indicated that currently-effective Reliability Standard EOP-005-2 could be misinterpreted to require Transmission Operators to validate every step of the restoration process with both steady state and dynamic simulation. NERC, therefore, clarifies that a Transmission Operator should perform a combination of steady state and dynamic simulations for the overall restoration process. This testing should occur at least once every five years.

g. EOP-005-2, Requirement R7

As discussed above, the proposed additional language, "develop and implement" added to EOP-005-3, Requirement R1 is redundant with EOP-005-2, Requirement R7. Therefore, NERC proposes to retire Requirement R7. This proposed retirement is consistent with a recommendation of the Panel.

The flexibility allotted to Transmission Operators to "utilize. . .restoration strategies to facilitate restoration" when "the restoration plan cannot be executed as expected" under Requirement R7 is preserved in Requirement R1, Part 1.1. Under Requirement R1, Part 1.1, restoration plans shall include "[s]trategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection." Transmission Operators retain the ability to deviate from their restoration plans if they cannot be executed as expected, so long as that approach is outlined in their strategies. The proposed deletion of Requirement R7 is not intended to diminish Transmission Operators' adaptive capability throughout the course of restoration activities.

h. EOP-005-2, Requirement R8

NERC proposes to retire currently-effective EOP-005-2, Requirement R8 because its requirements are captured in proposed EOP-005-3, Requirement R1, Part 1.1 and existing IRO-001-1.1 Requirement R3. Currently-effective Reliability Standard EOP-005-2, Requirement R8 calls for Transmission Operators to resynchronize, with the permission of the Reliability Coordinator, along with neighboring Transmission Operators where Blackstart Resources are required, to restore one or more areas of the BES shut down by a Disturbance. The EOP SDT notes that this coordination with neighboring Transmission Operators under Requirement R8 is still captured by Requirement R1, Part 1.1. Through this part, NERC mandates that Transmission Operators implement restoration plans which include "[s]trategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection." Even though Part 1.1 does not expressly call for such resynchronization, it is well understood by industry that such a step is integral to restoration activities. This critical restoration step helps to prevent against loss of load. The ability of the Reliability Coordinator to authorize such coordination and synchronization with neighboring Transmission Operators is captured by IRO-001-1.1, Requirement R3, which vests Reliability Coordinators with "clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System."

i. EOP-005-3, Proposed Requirement R8

Proposed Requirement R8 renumbers language from currently effective EOP-005-2, Requirement R10 and NERC proposes the following additional revisions. NERC proposes to delete language in the main body of proposed Requirement R8, as redundant language already addressed by training topics listed in Parts 8.1 through 8.5. NERC also proposes a new training topic for the Transmission Operator training program in Part 8.5. Specifically, NERC identifies a need to train on coordination with Balancing Authorities, specifically the transition of Demand

and resource balance within the Balancing Authority's Area. Proposed Requirement R8 is revised as follows:

~~R10~~ R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan~~. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R10.1~~8.1. System restoration plan including coordination with ~~the~~ its Reliability Coordinator and Generator Operators included in the restoration plan

~~R10.2~~8.2. Restoration priorities

~~R10.3~~8.3. Building of cranking paths

~~R10.4~~8.4. Synchronizing (re-energized sections of the System)

8.5. Transition to Balancing Authority for Demand and resource balance within its area.

j. EOP-005-3, Proposed Requirement R9

Proposed Requirement R9 renumbers language from currently-effective EOP-005-2, Requirement R11 and includes no revisions. Proposed Requirement R9 requires that a minimum of two hours of System restoration training be provided every two calendar years to field switching personnel performing "unique tasks" associated with the Transmission Operator's restoration plan that are outside of their normal tasks. In Order No. 749, in which the Commission approved several System Restoration Reliability Standards, the Commission stated that "[o]nce [EOP-005-2] is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."[29] The EOP SDT evaluated the use of "unique tasks" and concluded that its ordinary meaning, outside of everyday tasks conducted by switching personnel, is sufficient and does not require further clarification. While NERC may consider developing guidance in the future if

29 Order No. 749 at P 24.

compliance concerns arise surrounding defining "unique tasks," entities retain the discretion to define "unique tasks."

C. Proposed Reliability Standards EOP-006 – 3 – System Restoration Coordination

The purpose of proposed Reliability Standard EOP-006-3 is to establish how personnel should prepare, execute, and coordinate System restoration processes to maintain reliability and to restore the Interconnection. Proposed Reliability Standard EOP-006-3 improves upon the existing version of the standard in three ways:

(1) emphasizes the need for Reliability Coordinators to not only develop, but utilize their restoration plans;

(2) streamlines the standard and retires redundant or administrative requirements; and

(3) clarifies requirements around training and coordination of restoration plans amongst Reliability Coordinators.

In addition, NERC also proposes to retire Reliability Standard EOP-006-2, as described in the Implementation Plan for EOP-006-3 (See **Exhibit B**), to ensure a seamless transition to the newly revised standard.

1. Requirement-by-Requirement Justification

a. EOP-006-3, Proposed Requirement R1

NERC proposes a modification to Requirement R1 by replacing "have" with "develop and implement" language to emphasize the need for the Reliability Coordinator to possess and utilize its restoration plan for Real-time operations. The addition of the word "implement" requires the addition of "Real-time Operations" to the Time Horizon of this requirement. NERC proposes to delete Parts 1.2 through 1.4 from Reliability Standard EOP-006-2 as redundant with Reliability

Standard EOP-006-2, Part 1.5 (which is renumbered as Part 1.2 in proposed EOP-006-3) as shown below:

R1. Each Reliability Coordinator shall ~~have~~develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a ~~shut down~~shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

~~1.2. Operating Processes for restoring the Interconnection.~~

~~1.3. Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~

~~1.4. Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

~~1.5.~~1.2. Criteria and conditions for ~~reestablishing~~re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

~~1.6.~~1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

~~1.7.~~1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

~~1.8.~~1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

~~1.9.~~1.6. Criteria for transferring operations and authority back to the Balancing Authority.

b. EOP-006-3, Proposed Requirement R4

The EOP SDT found that an important step in resolving conflicts in the restoration plans of neighboring Reliability Coordinator's is for the reviewing Reliability Coordinator to provide the neighboring Reliability Coordinator with notice of the conflict. NERC proposes to add this notification requirement to Requirement R4. NERC also clarifies the timing for resolving conflicts as starting after receipt of written notification of a conflict. Requirement R4, Part 4.1 is revised as follows:

R4. Each Reliability Coordinator shall review ~~their~~<u>its</u> neighboring Reliability Coordinator's restoration plans~~.~~ <u>and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt.</u> [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. If ~~the~~<u>a</u> Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved <u>within</u> 30 calendar <u>days of receipt of written notification.</u>

c. EOP-006-3, Proposed Requirement R5

NERC proposes to clarify that the Reliability Coordinator must notify the Transmission Operator of its decision approving or disapproving a revised restoration plan per Reliability Standard EOP-005. Requirement R5, Part 5.1 is revised as follows:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall ~~approve~~ <u>provide notification to the Transmission Operator of approval</u> or disapprove~~e~~<u>al</u>, with stated reasons, <u>of</u> the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

d. EOP-006-3, Proposed Requirement R6

NERC replaces "implementation date" with "effective date" in Requirement R6 to clarify that the "implementation date" refers to any given use of a plan. Therefore, a given plan could have several implementation dates. "Effective date" more accurately represents the pertinent date when entities identified in a restoration plan should have a copy of a restoration plan changing roles and tasks for future implementation.

Requirement R6 is revised as follows:

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the ~~implementation~~effective date. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

e. EOP-006-2, Requirements R7 and R8

NERC proposes to retire Requirements R7 and R8 from currently-effective Reliability Standard EOP-006-2. The EOP SDT agrees with the recommendation of the Panel to retire these requirements as "a logical action that does not require a standard." The pending definition of "Reliability Coordinator" addresses all of the tasks included in Requirements R7 and R8. Requirements R7 and R8 offer examples of implementation steps taken by Reliability Coordinators and are subsumed by the proposed addition of "develop and implement" to Requirement R1 in proposed EOP-006-3.

f. EOP-006-3, Proposed Requirement R7

NERC notes that the language in currently-effective EOP-006-2, Requirement R9 is renumbered as proposed EOP-006-3, Requirement R7 due to proposed retirements in this standard. NERC proposes to delete the language "to assure the proper execution of its restoration plan" in Requirement R7,to streamline the language in the standard as follows:

R~~9~~7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan~~. This training program shall address the following: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R7~~9~~.1. The coordination role of the Reliability Coordinator~~.~~; and

R7~~9~~.2. Re~~-~~establishing the Interconnection.

g. EOP-006-3, Proposed Requirement R8

NERC notes that the language in currently-effective EOP-006-2, Requirement R10 is renumbered as proposed EOP-006-3, Requirement R8 due to proposed retirements in this standard. NERC purposes clarifying language for proposed Requirement R8 for the frequency for Transmission Operators and Generator Operators to participate in drills, exercises or simulations.

~~R10~~R8.Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

~~R10.1~~R8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

D. Proposed Reliability Standard EOP-008-2 – Loss of Control Center Functionality

The purpose of proposed Reliability Standard EOP-008-2 is to "[e]nsure continued reliable operations of the BES in the event that a control center becomes inoperable." Proposed Reliability Standard EOP-008-2 improves upon the existing Reliability Standard EOP-008-1 by clarifying the required contents of an Operating Plan used by Reliability Coordinators, Balancing Authorities and Transmission Operators. NERC proposes to retire currently-effective Reliability Standard

EOP-008-1 as described in the Implementation Plan for proposed EOP-008-2 (**See Exhibit B**) to ensure a seamless transition to the newly revised proposed standard.

1. Requirement-by-Requirement Justification

a. EOP-008-2, Proposed Requirement R1

NERC proposes to eliminate any ambiguity regarding the contents of an Operating Plan used by a Reliability Coordinator, Balancing Authority and Transmission Operator to maintain reliability of the BES when a primary control center loses its functionality. In Requirement R1, NERC proposes that the contents of an Operating Plan for backup functionality listed in Parts 1.1 – 1.6 represent an exhaustive list rather than a minimum threshold.

NERC also proposes to change several of the elements required in the Operating Plan for backup functionality. For Part 1.1., NERC removes the timing requirement to restore primary control center functionality due to the wide range of events that could render the primary control center inoperable. The EOP SDT found that it would be difficult for entities to assess their own compliance with this restoration requirement given this variable.

For Parts 1.2 and 1.6, NERC proposes that the list of elements required to support the backup functionality be exhaustive rather than a minimum threshold list. This provides Responsible Entities with clear direction regarding the contents of their Operating Plans. NERC amends two of these backup functionality elements. First NERC replaces “Voice communications” with “Interpersonal Communications” to account for the variety of media used by operators, consistent with Reliability Standard COM-001-2.1 (Communications), which also adopts the term “Interpersonal Communications.” “Interpersonal Communications” are defined as any medium that allows *two or more individuals* to interact, consult, or exchange information. This change is also consistent with the event type change in EOP-004-4.

Second, NERC replaces "Data communications" with "Data exchange capabilities." COM-001-2.1 addresses "Interpersonal Communication" which covers Voice communications, but not "Data exchange capabilities." The term "data exchange capabilities" relates to *facilities* that directly exchange or transfer data. The Commission adopted the term in Order No. 817, which approved revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards.[30] In Reliability Standard TOP-001-3, Requirements R19 and R20, NERC requires each Transmission Operator and Balancing Authority to have data exchange capabilities with the entities from which it needs data in order to maintain reliability in its area. The same Requirement applies to Reliability Coordinators with respect to their Balancing Authorities and Transmission Operators pursuant to IRO-002-4, Requirement R1 (Reliability Coordination – Monitoring and Analysis). These data exchange capabilities are required to support the data specifications required in Reliability Standard TOP-003-3 (Operational Reliability Data).

E. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

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[30] Order No. 817, *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 153 FERC ¶ 61,178, 80 Fed. Reg. 73,977. (2015).

The proposed Reliability Standards also include Measures that support each Requirement by identifying what is required and how the ERO will enforce the requirement. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[31]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve proposed Reliability Standards EOP-004-4, EOP-005-3, EOP-006-3, and EOP-008-2 to become effective as set forth in the proposed Implementation Plans, provided in Exhibit B hereto. The proposed Implementation Plans provide that the proposed Reliability Standard shall become effective on the first day of the first calendar quarter that is 12 calendar months after the effective date of the Commission's order approving the proposed Reliability Standard, or as otherwise provided for by the Commission.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Reliability Standards included in **Exhibit A,** effective as proposed herein;
- the Implementation Plans included in **Exhibit B**; and
- the retirement of currently-effective Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2, and EOP-008-1, effective as proposed herein.

[31] Order No. 672 at P 327.

Respectfully submitted,

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March 27, 2017

Exhibit A

Proposed Reliability Standards

Exhibit A-1

Proposed Reliability Standard EOP-004-4

Reliability Standard EOP-004-4 Clean and Redline

EOP-004-4 Clean Version

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load sheddingresulting from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form

Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."

	Task	Comments
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical threat to its Facility ☐ Physical threat to its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	Written description (optional):

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	
4	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

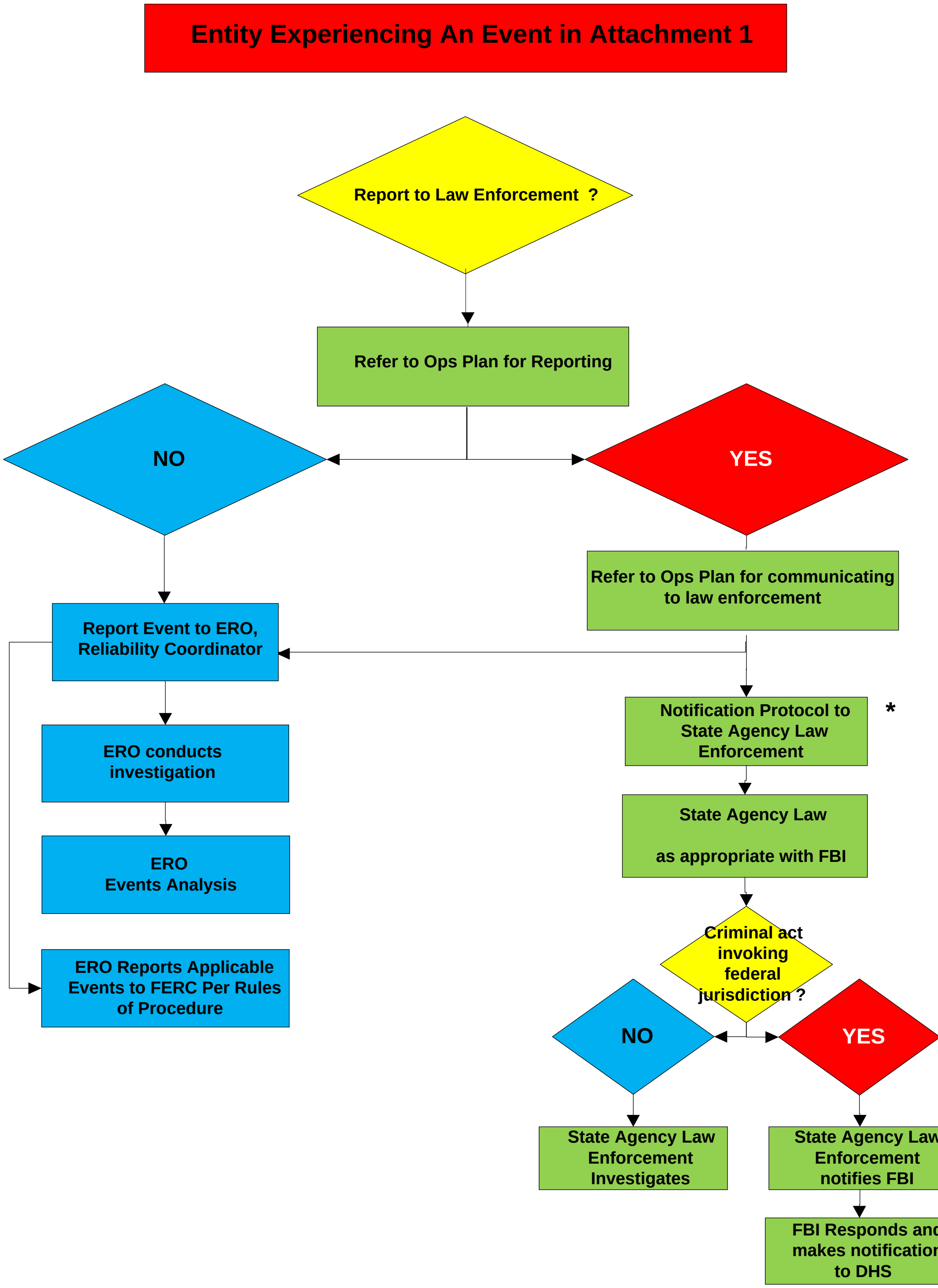
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

EOP-004-4 Redline Version

A. ~~A.~~ Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-~~3~~4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following ~~functional entities~~Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

~~5.~~ Effective ~~Dates:~~

Date: See the Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme"~~

~~**6. Background:**~~

5. ~~NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and~~ EOP-004 ~~Reliability Standards. The team was asked to consider the following:~~ -4.

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

B. ~~B.~~ Requirements and Measures

~~R1.~~

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2~~ ~~3~~4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. ~~**M1.**~~ Each Responsible Entity will have a dated event reporting Operating Plan that includes~~, but is not limited to the~~ protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. ~~**R2.**~~ Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan ~~within~~by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM~~(4 p.m. local time ~~on Friday to 8 AM Monday local time).~~will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. ~~M2.~~ Each Responsible Entity will have as evidence of reporting an event~~,~~ to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-~~3~~4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted ~~within~~ by the later of 24 hours of recognition of meeting ~~the~~an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be~~ (4 ~~PM~~p.m. local time ~~on Friday to 8 AM Monday local time). (R2)~~will be considered the end of the business day).

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. ~~C.~~ Compliance

1. ~~1.~~ Compliance Monitoring Process

1.1. ~~1.1~~ Compliance Enforcement Authority:

~~The Regional Entity shall serve as the~~ "Compliance Enforcement Authority ~~(CEA) unless the applicable~~" means NERC or the Regional Entity, or any entity ~~is owned, operated, or controlled~~as otherwise designated by ~~the Regional Entity. In such cases the ERO~~ an Applicable Governmental Authority, in their respective roles of monitoring and/or ~~a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA~~enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~1.2~~ Evidence Retention:

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for ~~Requirements~~Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for ~~Requirements~~Requirement R2~~, R3~~ and Measure M2~~, M3~~.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.3~~

1.3. Compliance Monitoring and Enforcement ~~Processes:~~Program

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.4 Additional Compliance Information~~

~~None~~

~~Table of Compliance Elements~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~Operations Planning~~	~~Lower~~	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	~~Operations Assessment~~	~~Medium~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients ~~more than~~up to 24 hours ~~but less than or equal to 36 hours~~ after ~~meeting an event threshold~~the timing requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~24 hours but less than or equal to 48 hours after ~~meeting an event threshold~~the timing requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~72 hours after ~~meeting an event threshold~~the timing requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~60~~72 hours after ~~meeting an event threshold~~the timing requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R3~~	~~Operations Planning~~	~~Medium~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~OR~~ ~~The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.~~ ~~OR~~ ~~The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.~~

~~D.~~

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F. References~~

~~Guideline and Technical Basis (attached)~~

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written ~~Event Report~~event report within the timing in the standard.~~-~~ In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. ~~-~~Submit reports to the ERO via one of the following: e-mail:~~-~~ systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:
System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."
Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in ~~actions~~action(s) to avoid a BES Emergency.
Damage or destruction of ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a Facility.~~ ~~Do not report theft unless it degrades normal operation of a~~its Facility.
Physical threats to ~~a~~its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~its BES control center.
~~BES Emergency requiring public~~Public appeal for load reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~BA	Public appeal for load reduction ~~event~~to maintain continuity of the BES.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring system~~System-wide voltage reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~TOP	System--wide voltage reduction of 3% or more.
~~BES Emergency requiring manual firm load shedding~~	~~Initiating entity is responsible for reporting~~	~~Manual firm load shedding ≥ 100 MW.~~
Firm load sheddingresulting from a BES Emergency ~~resulting in automatic firm load shedding~~	~~DP,~~Initiating RC, BA, or TOP	~~Automatic firm~~Firm load shedding ≥ 100 MW (~~via~~manual or automatic ~~undervoltage or underfrequency load shedding schemes, or RAS~~).
~~Voltage~~BES Emergency resulting in voltage deviation on a Facility	TOP	~~Observed within its area a~~A voltage deviation of ~~±~~=/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~Loss~~Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	~~Loss~~Uncontrolled loss of firm load for ≥ 15 ~~Minutes:~~minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of~~-~~: ≥ 2,000 MW ~~for entities~~ in the Eastern ~~or~~, Western ~~Interconnection~~ ~~OR~~ ~~≥ 1,000 MW for entities in the ERCOT~~ , or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface ~~Requirement~~Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES ~~Elements~~Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center ~~evacuation~~	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability affecting ~~a~~its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability ~~affecting a~~at its staffed BES control center for 30 continuous minutes or more ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net~~,~~, Facsimile 404-446-9770 or voice: 404-446-9780~~.~~, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical ~~Threat~~threat to ~~a~~its Facility ☐ Physical ~~Threat~~threat to ~~a~~its BES control center ☐ BES Emergency:_______ ☐ firm load shedding ☐ public appeal for load reduction ~~☐ system~~ ☐ System-wide voltage reduction ~~☐ manual firm load shedding~~ ~~☐ automatic firm load shedding~~ ~~☐ Voltage~~ ☐ voltage deviation on a Facility ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~ ~~☐ Loss~~ ☐ uncontrolled loss of firm load ☐ System separation (islanding)	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form	
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net~~,~~ Facsimile 404-446-9770 or voice: 404-446-9780~~, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."~~	
Task	**Comments**
☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ ~~unplanned~~Unplanned evacuation of its BES control center ~~evacuation~~ ☐ Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

4	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**Data Gathering**~~

~~The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~Present expectations of the industry under CIP-001-1a:~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~Coordination of Local and State Law Enforcement Agencies with the FBI~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

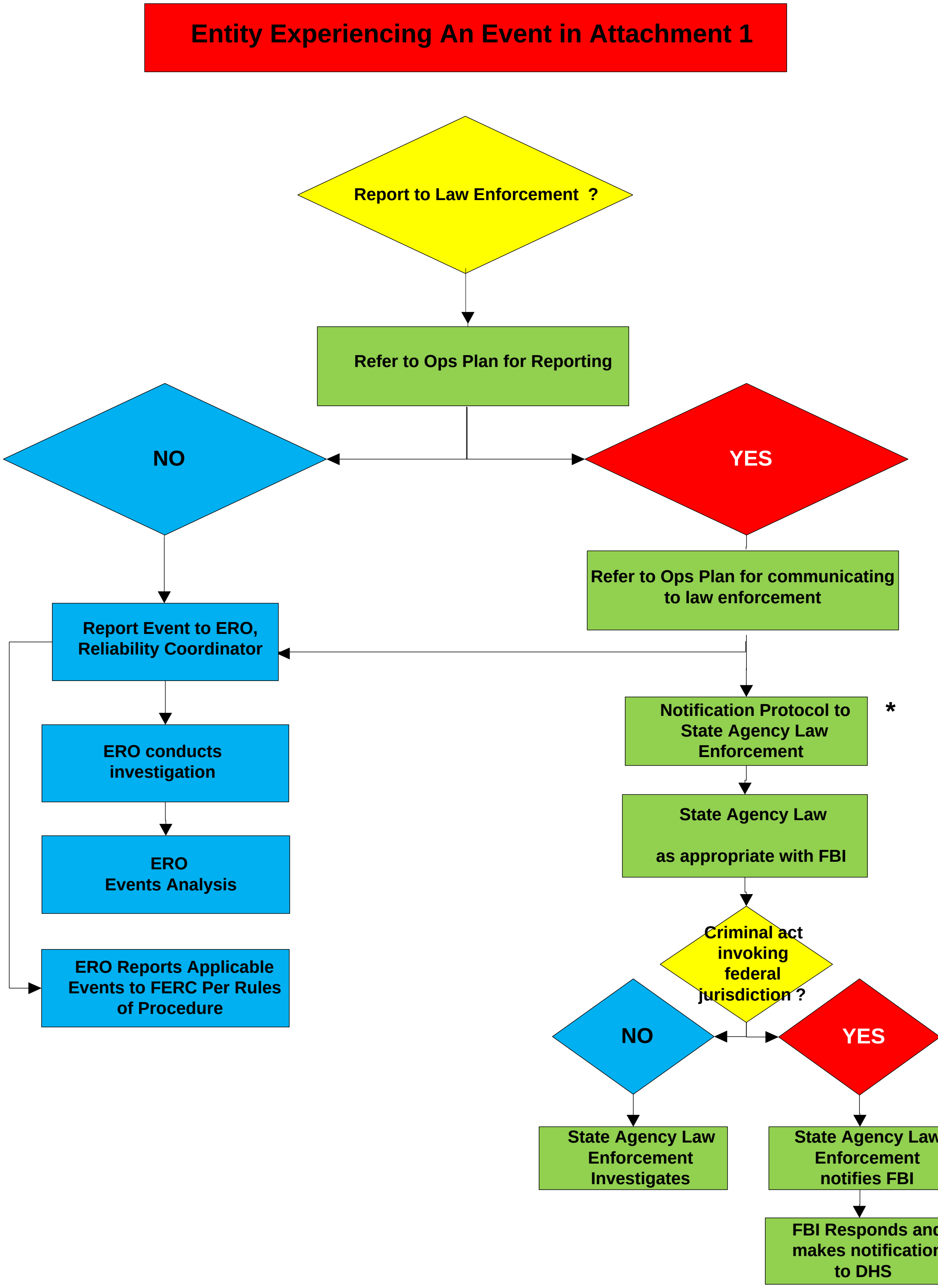
~~Coordination of Local and Provincial Law Enforcement Agencies with the RCMP~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~A Reporting Process Solution – EOP-004~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

~~Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts~~

~~Introduction~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.~~

~~The standards listed under the SAR are:~~

- ~~CIP-001 — Sabotage Reporting~~
- ~~EOP-004 — Disturbance Reporting~~

~~The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.~~

~~The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.~~

~~Summary of Concepts and Assumptions:~~

~~The Standard:~~

- ~~Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System~~
- ~~Provides clear criteria for reporting~~
- ~~Includes consistent reporting timelines~~
- ~~Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting~~
- ~~Provides clarity around of who will receive the information~~

~~*Discussion of Disturbance Reporting*~~

~~Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:~~

1. ~~An unplanned event that produces an abnormal system condition.~~
2. ~~Any perturbation to the electric system.~~
3. ~~The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.~~

~~Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

- ~~Bolts removed from transmission line structures~~
- ~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~
- ~~Destruction of Bulk Electric System equipment~~

~~***What about sabotage?***~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part:~~ ~~*". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

~~Event analysis~~General situational awareness, correlation of data, ~~and~~ trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional ~~entities~~Entities to report the incidents and provide ~~known~~ information known at the time of the report. Further data gathering necessary for ~~event~~ analysis is provided for under the ~~Events~~ERO Event Analysis Program and the NERC Rules of Procedure. ~~Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses.~~ The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~Collection of Reportable Information or "One stop shopping"~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be~~

~~necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for R1:~~

~~The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.~~

~~Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective.~~

~~The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.~~

~~Rationale for R2:~~

~~Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

~~**Rationale for R3:**~~

~~Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.~~

~~**Rationale for EOP-004 Attachment 1:**~~

~~The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:~~

> ~~"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"~~

~~The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.~~

~~Version History~~

~~**Version**~~	~~**Date**~~	~~**Action**~~	~~**Change Tracking**~~
~~2~~		~~Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.~~	~~Revision to entire standard (Project 2009-01)~~

~~2~~	~~November 7, 2012~~	~~Adopted by the NERC Board of Trustees~~	
~~2~~	~~June 20, 2013~~	~~FERC approved~~	
~~3~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~3~~	~~November 19, 2015~~	~~FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.~~	

Exhibit A-2

Proposed Reliability Standard EOP-005-3

Reliability Standard EOP-005-3 Clean and Redline

EOP-005-3 Clean Version

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Transmission Operators
   4.1.2. Generator Operators
   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan
   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan
5. **Effective Date:** See the Implementation Plan for EOP-005-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

R4. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation, such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. .

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in effect since its last compliance audit for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in effect since its last compliance audit on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator prior

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from its Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator	N/A	The Transmission Operator and Generator Operator

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.		with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in its Reliability Coordinator’s

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Rationale

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

EOP-005-3 Redline Version

A. Introduction

1. **Title:** System Restoration from Blackstart Resources

2. **Number:** EOP-005-~~2~~3

3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ~~assure~~ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

4.1. Functional Entities:

~~4.1.~~**4.1.1.** Transmission Operators~~.~~

~~4.2.~~**4.1.2.** Generator Operators~~.~~

~~4.3.~~**4.1.3.** Transmission Owners identified in the Transmission Operators restoration plan~~.~~

~~4.4.~~**4.1.4.** Distribution Providers identified in the Transmission Operators restoration plan~~.~~

~~5. **Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

5. **Effective Date:** See the Implementation Plan for EOP-005-3.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall ~~have~~develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~shutdown area~~ to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

~~R1.1.~~**1.1.** Strategies for ~~system~~System restoration that are coordinated with ~~the~~its Reliability Coordinator's high level strategy for restoring the Interconnection.

~~R1.2.~~**1.2.** A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

~~R1.3.~~1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~its Reliability Coordinator.

~~R1.4.~~1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

~~R1.5.~~1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

~~R1.6.~~1.6. Identification of acceptable operating voltage and frequency limits during restoration.

~~R1.7.~~1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

~~R1.8.~~1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

~~R1.9.~~1.9. Operating Processes for transferring ~~authority~~operations back to the Balancing Authority in accordance with ~~the~~its Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

~~**R3.**~~ Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually~~-~~agreed, predetermined schedule. ~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~

~~**3.1.** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to~~

~~its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retirement approved by FERC effective January 21, 2014.)~~

~~R4.~~R3. ~~Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

~~R4.1.~~R4. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval ~~within the same 90 calendar day period.~~ , when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its ~~implementation~~effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years ~~at a minimum.~~ . Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

~~R6.1.~~6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

~~R6.2.~~6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

~~R6.3.~~6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

~~R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected~~Each Transmission Operator shall ~~implement~~have documentation, such as power flow outputs, that it has verified that its latest restoration plan~~. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize~~ will accomplish its ~~restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~R8.~~M6. ~~Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or~~intended function in accordance with ~~the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~Requirement R6.

~~R9.~~R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R9.1.~~7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

~~R9.2.~~7.2. A list of required tests including:

~~R9.2.1.~~7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

~~R9.2.2.~~7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

~~R9.3.~~M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

~~R10.~~R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan.~~. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R10.1.~~8.1. System restoration plan including coordination with ~~the~~its Reliability Coordinator and Generator Operators included in the restoration plan.

~~R10.2.~~8.2. Restoration priorities.

~~R10.3.~~8.3. Building of cranking paths.

~~R10.4.~~8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

~~R11.~~R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

~~R12.~~R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

~~R13.~~R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

~~R14.~~R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

~~R15.~~R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

~~R16.~~R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- ~~R16.1.~~14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement ~~R9~~R7.
- ~~R16.2.~~14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

~~R17.~~R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- ~~R17.1.~~15.1. System restoration plan including coordination with the Transmission Operator~~.~~
- ~~17.2.~~ The procedures documented in Requirement ~~R14.~~

~~**R18.** Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~

~~C. Measures~~

~~**M1.** Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.~~

~~**M2.** Each Transmission Operator shall have evidence such as e-mails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.~~

~~**M3.** Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, e-mails with receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.~~

~~**M4.** Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails with receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.~~

~~**M5.** Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.~~

~~**M6.** Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.~~

~~**M7.** If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.~~

~~**M8.** If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.~~

~~**M9.** Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R9.~~

~~**M10.** Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R10.~~

~~**M11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R11.~~

~~**M12.**~~**15.2.** ~~Each Transmission Operator shall have evidence, such as training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement~~ R12~~.~~

~~**M13.** Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R13.~~

~~**M14.** Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R14.~~

~~**M15.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within twenty-four hours of such changes in accordance with Requirement R15.~~

~~**M16.** Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R16.~~

~~**M17.**~~**M15.** Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement ~~R17~~R15.

R16. Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~**M18.**~~**M16.** Each Generator Operator shall have evidence~~, such as dated training records,~~ that it participated in ~~the~~its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement ~~R18~~R16.

~~D.~~C. Compliance

1. **Compliance Monitoring Process**

~~1.4.~~ Compliance Enforcement Authority

1.1. : Regional Entity~~.~~

~~1.5. Compliance Monitoring Period and Reset Time Frame~~

~~Not applicable.~~

~~1.6. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.7. Data Retention~~

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- ~~o~~ Approved restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- ~~o~~ Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.

- ~~o~~ Submission of the Transmission Operator's annually~~-~~-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- ~~o~~ Submission of ~~an updated~~a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- ~~o~~ The current~~,~~ restoration plan approved by ~~the~~its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- ~~o~~ The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
  - ~~o Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.~~
  - ~~o Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.~~
- ~~o~~ The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement ~~R9~~R7, Measure ~~M9~~M7.
- ~~o Actual training~~Training program materials or descriptions for three calendar years for Requirement ~~R10~~R8, Measure ~~M10~~M8.
- ~~o~~ Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R12~~R10, Measure ~~M12~~M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer. The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

~~The Transmission Operator, applicable Transmission Owner, and applicable Distribution provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~o~~ ~~Actual training~~Training program materials or descriptions and ~~actual~~ training records for three calendar years for Requirement ~~R11~~R9, Measure ~~M11~~M9.

If a Transmission Operator, applicable Transmission ~~owner~~Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer. .

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- ~~o~~ Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in ~~force~~effect since its last compliance audit for Requirement ~~R13~~R11, Measure ~~M13~~M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- ~~o~~ Current documentation and any documentation in ~~force~~effect since its last compliance audit on procedures to start each Blackstart ~~Resources~~Resource and for energizing a bus for Requirement ~~R14~~R12, Measure ~~M14~~M12.
- ~~o~~ Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement ~~R15~~R13, Measure ~~M15~~M13.
- ~~o~~ The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement ~~R16~~R14, Measure ~~M16~~M14.
- ~~o~~ ~~Actual training~~Training program materials and ~~actual~~ training records for three calendar years for Requirement ~~R17~~R15, Measure ~~M17~~M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- ~~o~~ Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement ~~R18~~R16, Measure ~~M18.~~ M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance audit records.

1.3. ~~The~~ **Compliance Monitoring and Enforcement** ~~Authority shall keep~~**Program**

As defined in the ~~last audit records and all requested and submitted subsequent audit records~~NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.8. Additional Compliance Information**~~

~~None.~~

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	–The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was up to 10~~	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more~~	-The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more~~	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. OR

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~calendar days late in doing so.~~	~~than 10 and less than or equal to 20 calendar days late in doing so.~~	~~than 20 and less than or equal to 30 calendar days late in doing so.~~	~~The~~ Transmission Operator ~~provided~~failed to provide at least half of the ~~information to all~~ entities ~~but was more than 30 calendar days late~~identified in ~~doing so~~its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ within 30 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 30 and less than or equal to 60 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 60 and less than or equal to 90 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 90 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator within 90 calendar days of an	The Transmission Operator ~~failed to update and submit~~submitted its revised restoration plan to ~~the~~its Reliability Coordinator ~~within more than 90~~between	The Transmission Operator ~~has failed to update and submit~~submitted its revised restoration plan to ~~the~~its Reliability Coordinator ~~within more than 120~~between	The Transmission Operator has failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator within ~~more than~~ 150

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	unplanned ~~change.~~permanent System BES modification.	91 calendar days ~~but less than120~~and 120 calendar days of an unplanned ~~change.~~permanent System BES modification.	121 calendar days ~~but less than~~ and 150 calendar days of an unplanned ~~change~~permanent System BES modification.	calendar days of an unplanned ~~change.~~ permanent System BES modification. OR The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator prior to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its ~~implementation~~effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not	-The Transmission Operator performed the verification within the required timeframe but did not	-The Transmission Operator performed the verification but did not complete it	The Transmission Operator did not perform the verification or it took more

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	comply with one of the ~~sub-requirements.~~ requirement parts.	comply with two of the ~~sub-requirements.~~ requirement parts.	within the ~~five calendar year period~~required time frame.	than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the ~~sub-requirements.~~ requirement parts.
~~R7.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not implement its restoration plan following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES. Or, if the restoration plan cannot be executed as expected, the Transmission Operator did not utilize its restoration plan strategies to facilitate restoration.~~
~~R8.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the~~

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service.~~
~~R9.~~ R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the ~~sub-requirements~~requirement parts of Requirement ~~R9.~~ R7.
R8.~~R10.~~	The Transmission Operator's training does not address one of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address two of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address three or more of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.~~R11.~~	The Transmission Operator, applicable Transmission Owner, or applicable	The Transmission Operator, applicable Transmission Owner, or applicable	The Transmission Operator, applicable Transmission Owner, or applicable	The Transmission Operator, applicable Transmission Owner, or applicable

~~R #~~	~~Violation Severity Levels~~			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Distribution Provider failed to train 5% or less of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.	Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.	Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement ~~R11 within a~~R9 two-calendar-year period.	Distribution Provider failed to train more than 15% of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.
R10.~~R12.~~	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for ~~their~~its participation from ~~the~~its Reliability Coordinator.
R11.~~R13.~~	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
~~R14.~~ **R12.**	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				procedures for each Blackstart Resource.
R13.~~R15.~~	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.
R14.~~R16.~~	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in ~~R16.1.~~Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 ~~days~~ to 90 calendar days after the request.	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

~~R #~~	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	requested for 31 to 60 calendar days ~~of~~after the request.			
R15.~~R17.~~	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement ~~R17~~R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement ~~R17~~R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement ~~R17~~R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement ~~R17~~R15 within a two-calendar-year period.
R16.~~R18.~~	N/A	N/A	N/A	The Generator Operator failed to participate in ~~the~~its Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~its Reliability Coordinator.

~~E.~~D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2	~~TBD~~	Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements . Updated Measures and Compliance to match new ~~Requirements~~ requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval~~.~~	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval~~.~~	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Rationale

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

Exhibit A-3

Proposed Reliability Standard EOP-006-3

Reliability Standard EOP-006-3 Clean and Redline

EOP-006-3 Clean Version

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability

Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its

Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator; and

7.2. Re-establishing the Interconnection.

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.

- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program,	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

EOP-006-3 Redline Version

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-~~2~~ 3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

4.1. Functional Entities:

~~4.1.~~**4.1.1.** Reliability Coordinators~~.~~

~~**5.Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall ~~have~~develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a ~~shut down~~shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

~~**R1.1.**~~**1.1.** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

~~**R1.2.** Operating Processes for restoring the Interconnection.~~

~~**R1.3.** Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~

~~**R1.4.** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

~~**R1.5.**~~**1.2.** Criteria and conditions for ~~reestablishing~~re-establishing interconnections with other Transmission Operators within its Reliability

Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

~~R1.6.~~1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

~~R1.7.~~1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

~~R1.8.~~1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

~~R1.9.~~1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review ~~their~~its neighboring Reliability Coordinator's restoration plans~~.~~ and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If ~~the~~a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved ~~in~~within 30 calendar days~~.~~ of receipt of written notification.

~~R4.1.~~**M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R5.1.~~5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall ~~approve~~provide notification to the Transmission Operator of approval or ~~disapprove~~disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the ~~implementation~~effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

~~R7.~~**M6.** Each Reliability Coordinator shall ~~work with its affected Generator Operators, and Transmission Operators~~have documentation such as ~~well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the~~ electronic receipts that it has made the latest copy of its restoration plan ~~cannot be completed as expected the~~ and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator ~~shall utilize its restoration plan strategies to facilitate~~Area available in its primary and backup control rooms and to each of its System ~~restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~ Operators prior to the effective date in accordance with Requirement R6.

~~R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~R9.~~R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan.~~ . This training program shall address the following: ~~–~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R9.1.~~7.1. The coordination role of the Reliability Coordinator ~~.~~; and

7.2. ~~Reestablishing~~Re-establishing the Interconnection.

~~R9.2.~~M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

~~R10.~~R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R10.1.~~8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

~~C.~~Measures

~~M1.~~Each Reliability Coordinator shall have ~~available a dated copy of its restoration plan in accordance with Requirement R1.~~

~~M2.Each Reliability Coordinator shall provide~~ evidence, such as ~~e-mails with receipts, posting to a secure web site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.~~

~~M3.M1. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.~~

~~M4.Each Reliability Coordinator shall provide evidence such as dated review signature sheets that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.~~

~~M5.Each Reliability Coordinator shall provide evidence, such as a review signature sheet or emails, that it has reviewed, approved or disapproved, and notified its Transmission Operator's within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.~~

~~M6.Each Reliability Coordinator shall have documentation such as e-mail receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its~~

~~primary and backup control rooms and to each of its System Operators prior to the implementation date in accordance with Requirement R6.~~

~~**M7.**Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.~~

~~**M8.**If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.~~

~~**M9.**Each Reliability Coordinator shall have an~~ dated electronic ~~or hard copy of its training records available showing that it has provided training in accordance with Requirement R9.~~

~~**M10.**~~**M8.** ~~Each Reliability Coordinator shall have evidence~~documents, that it conducted two System restoration drills, exercises, or simulations per calendar year ~~and that Transmission Operators~~ in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator ~~Operators included in the Reliability Coordinator's restoration plan were invited in accordance with Requirement R10.~~Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

~~D.~~C. Compliance

1. Compliance Monitoring Process

~~1.4.~~1.1. Compliance Enforcement Authority:

~~Regional Entity.~~

~~1.2.Compliance Monitoring Period and Reset Time Frame~~

~~Not applicable.~~

~~1.3.Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.4.Data Retention~~

~~The Reliability Coordinator~~"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- The current restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in ~~force~~effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in ~~force~~effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
  - ~~If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R7, Measure M7.~~
  - ~~If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R8, Measure M8.~~
- Actual training program materials or descriptions for three calendar years for Requirements ~~R9~~R7, Measure ~~M9.~~ M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R10~~R8, Measure ~~M10~~M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.5.~~1.3. ~~Additional~~ Compliance ~~Information~~ Monitoring and Enforcement Program

~~None.~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one ~~sub-~~requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two ~~sub-requirements~~requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the ~~sub-~~requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the ~~sub-requirements~~requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
~~R4~~R5.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~60~~45 calendar days of receipt.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~90~~60 calendar days~~.~~ of receipt.	~~–~~The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~120~~90 calendar days~~.~~ of receipt.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators ~~within 120~~for more than 90 calendar days~~.~~ of receipt. OR

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System	The Reliability Coordinator did not include the annual System restoration training

~~R #~~	~~Violation Severity Levels~~			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
			restoration training within its operations training program, but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

~~R5.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt. .~~
~~R6.~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.~~	~~The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.~~

~~**R7.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ ~~OR~~ ~~When the restoration plan cannot be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate System restoration.~~
~~**R8.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.~~ ~~OR~~ ~~If the resynchronization could not be completed as expected, the Reliability Coordinator did not utilize its restoration plan~~

				~~strategies to facilitate resynchronization.~~
~~**R9.**~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the sub-requirements.~~	~~The Reliability Coordinator did not include the annual System restoration training within its operations training program.~~
~~**R10.**~~	~~The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~	~~The Reliability Coordinator did not invite a Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.~~	~~N/A~~	~~The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.~~

~~E.~~D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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~~Nov. 1, 2006	Adopted by Board of Trustees	Revised
2	~~TBD~~	Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Exhibit A-4

Proposed Reliability Standard EOP-008-2

Reliability Standard EOP-008-2 Clean and Redline

EOP-008-2 Clean Version

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority
5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data exchange capabilities.

1.2.3. Interpersonal Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has

demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in effect document and any such documents in effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				primary control center functionality.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted an annual test of	The responsible entity conducted an annual test of	The responsible entity conducted an annual test of	The responsible entity did not conduct an annual test

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	
2	July 9, 2017	Adopted by the NERC Board of Trustees	Revised

Rationale

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

EOP-008-2 Redline Version

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-~~1~~2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   ~~1.1.~~**4.1. Functional** ~~Entity~~ **Entities:**

   ~~1.1.1~~**4.1.1.** Reliability Coordinator~~.~~

   ~~1.1.2~~**4.1.2.** Transmission Operator~~.~~

   ~~1.1.3~~**4.1.3.** Balancing Authority~~.~~

~~**Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.~~

5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. -This Operating Plan for backup functionality shall include ~~the following, at a minimum~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality ~~for the time it takes to restore the primary control center functionality.~~.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include~~, at a minimum:~~:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data ~~communications.~~ exchange capabilities.

~~**1.1.1.** Voice communications.~~

1.2.3. Interpersonal Communications.

~~1.2.3.~~**1.2.4.** Power source(s).

~~1.2.4.~~**1.2.5.** Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include ~~at a minimum~~:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards ~~that depend on~~are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing ~~Authority~~Authority's and Transmission Operator's primary control center functionality ~~respectively.~~ . To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~1.7.~~5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~–~~to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~1.8.~~7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

~~1.9.~~7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~C. Measures~~

~~**M1**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.~~

~~**M2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.~~

~~**M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.~~

~~**M4.** Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.~~

~~**M5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.~~

~~**M1.** **M6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.~~

~~**M1.** **M7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.~~

M8. ~~**M8.**~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~Regional Entity.~~

~~1.2. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.3. Data Retention~~

~~The Reliability Coordinator, Balancing Authority, and Transmission Operator~~"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall ~~retain~~keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in ~~force~~effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in ~~force~~effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.

- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality in accordance with Measurement M3.

- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing ~~Authority~~Authority's and Transmission Operator's primary control center functionality ~~respectively~~ in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in ~~force~~effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in ~~force~~effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and ~~one~~the previous ~~year~~calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in ~~force~~effect document and any such documents in ~~force~~effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

~~1.4.~~1.3. ~~Additional~~ Compliance ~~Information~~ Monitoring and Enforcement Program

~~None.~~

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~2.~~ Violation Severity Levels

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts ~~(~~1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts ~~(~~1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts ~~(~~1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts ~~(~~1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality.

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Authority~~Authority's and Transmission Operator's primary control center functionality ~~respectively.~~ .
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
			more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. ~~E.~~ Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~2009 - 2010	~~Revisions for~~ Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board ~~of Trustees~~	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval~~.~~	
2	July 9, 2017	Adopted by the NERC Board of Trustees	Revised

Rationale

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

Exhibit B

Implementation Plans

Exhibit B-1

Implementation Plan for Proposed Reliability Standard EOP-004-4

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)
None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background
Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date
EOP-004-4 — Event Reporting
Where approval by an Applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Exhibit B-2

Implementation Plan for Proposed Reliability Standards EOP-005-3, EOP-006-3 and EOP-008-2

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Exhibit C

Order No. 672 Criteria

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The proposed Reliability Standards achieve specific reliability goals. Proposed Reliability Standard EOP-004-4 – Event Reporting, improves the reliability of the Bulk Electric System ("BES") by requiring the reporting of events by Responsible Entities. Proposed Reliability Standard EOP-005-3 – System Restoration from Blackstart Resources, ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection. Proposed Reliability Standard EOP-006-3 – System Restoration Coordination, ensures plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection. Proposed Reliability Standard EOP-008-2 – Loss of Control Center Functionality, ensures continued reliable operations of the BES in the event that a control center becomes inoperable.

The proposed Reliability Standards also satisfy an outstanding Commission directive from Order No. 749.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]**

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard EOP-004-4, applies to Reliability Coordinators, Balancing Authorities, Transmission Owners, Transmission Operators, Generator Owners, Generator Operators, and Distribution Providers. Proposed Reliability Standard EOP-005-3, applies to Transmission Operators, Generator Operators, Transmission Owners identified in the Transmission Operators restoration plan and Distribution Providers identified in the Transmission Operators restoration plan. Proposed Reliability Standard EOP-006-3, applies to Reliability Coordinators. Proposed Reliability Standard EOP-008-2, applies to Reliability Coordinators, Transmission Operators, and Balancing Authorities. The proposed standards clearly articulate the actions that each entity must take to comply.

3. **A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]**

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for each of the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit E**. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of

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[3] Order No. 672 at P 322, 325.

[4] Order No. 672 at P 326.

similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [5]

The proposed Reliability Standards contain Measures that support each Requirement by clearly identifying what is required to demonstrate compliance. These Measures help provide clarity regarding the manner in which the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. Consistent with a Commission directive in Order No. 749, the proposed Reliability Standards improve upon the prior versions of the standards by: (i) ensuring strong planning, reporting, communication, and coordination across the Functional Entities; (ii) streamlining standards; and (iii) applying Paragraph 81 criteria, while making the standards more-Results-based.

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5 Order No. 672 at P 327.
6 Order No. 672 at P 328.

6. **Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]**

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the revisions reflected in the proposed Standards provide significant benefits for the reliability of the Bulk-Power System. The requirements of the proposed Reliability Standards clarify the methodology requirements for Emergency operations, including the communication and coordination amongst reporting entities.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

The proposed Reliability Standards have no undue negative effect on competition. The proposed Reliability Standards require the same performance by each applicable entity. The proposed standards do not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

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[7] Order No. 672 at PP 329-330.
[8] Order No. 672 at P 331.
[9] Order No. 672 at P 332.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for the proposed Reliability Standards that is the first day of the first calendar quarter that is twelve (12) months after the effective date of regulatory approval.

The proposed implementation periods are designed to allow sufficient time for the applicable entities to make any changes in their internal process necessary to implement proposed standards. The proposed effective dates are explained in the proposed Implementation Plans, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards.[12] **Exhibit G** includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

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[10] Order No. 672 at P 333.

[11] Order No. 672 at P 334.

[12] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[13] Order No. 672 at P 335.

[14] Order No. 672 at P 323.

Exhibit D

Mapping Documents

Exhibit D-1

Mapping Document for Proposed Reliability Standard EOP-004-4

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-3, Measure M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.	EOP-004-4, Measure M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.	Updated standard version number. "…not limited to" removed from Measure M1, as unnecessary.
EOP-004-3, Requirement R2 **R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM	EOP-004-4, Requirement R2 **R2.** Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business	Requirement R2 revisions were provided for clarity; to remove the ambiguity for weekends and to add clarity for holidays.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
local time on Friday to 8 AM Monday local time).	day (4 p.m. local time will be considered the end of the business day).	
EOP-004-3, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)	EOP-004-4, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	Measure M2 was updated for clarity and to identify 4:00 p.m. local time to be considered as the end of the entity's business day.
EOP-004-3, Requirement R3	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.		004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.
EOP-004-3, Attachment 1 Event Type: Damage or destruction of a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action.	EOP-004-4, Attachment 1 Event Type: Damage or destruction of its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-3, Attachment 1	EOP-004-4, Attachment 1	The EOP SDT wanted to change the reporting responsibility to the Facility

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Event Type: Physical threats to a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	Event Type: Physical threats to its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.	owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-3, Attachment 1 Event Type: Physical threats to a BES control center Entity with Reporting Responsibility: RC, BA, TOP	EOP-004-4, Attachment 1 Event Type: Physical threats to its BES control center Entity with Reporting Responsibility: RC, BA, TOP	With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.	Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.	
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring public appeal for load reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Public appeal for load reduction event.	EOP-004-4, Attachment 1 Event Type: Public appeal for load reduction resulting from a BES Emergency Entity with Reporting Responsibility: BA Threshold for Reporting: Public appeal for load reduction to maintain continuity of the BES.	To maintain the continuity of the BES was added to better align with the DOE OE-417 reporting category. Rationale: The EOP SDT changed the reporting responsibility to the BA only based on the BA requirements in EOP-011-1 (FERC approved, pending enforcement) Requirement R2 "Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions;

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring system-wide voltage reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting. Threshold for Reporting: System wide voltage reduction of 3% or more.	EOP-004-4, Attachment 1 Event Type: System-wide voltage reduction resulting from a BES Emergency Entity with Reporting Responsibility: TOP Threshold for Reporting: System-wide voltage reduction of 3% or more.	The TOP is operating the system and is the only entity that would implement System-wide voltage reduction.
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring manual firm load shedding Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Manual firm load shedding ≥ 100 MW.	EOP-004-4, Attachment 1 Event Type: Firm load shedding resulting from a BES Emergency Entity with Reporting Responsibility: Initiating RC, BA, or TOP Threshold for Reporting: Firm load shedding ≥ 100 MW (manual or automatic).	The RC, BA and TOP are the entities that would initiate manual firm load shedding.
EOP-004-3, Attachment 1 Event Type: BES Emergency resulting in automatic firm load shedding Entity with Reporting Responsibility: DP, TOP	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).		
EOP-004-3, Attachment 1 Event Type: Voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	EOP-004-4, Attachment 1 Event Type: BES Emergency resulting in voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.	To provide clarity to the Event Type and to the Threshold for Reporting, the language revisions were made.
EOP-004-3, Attachment 1 Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Entity with Reporting Responsibility: RC Threshold for Reporting: Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement. Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) are in the new standard TOP-001-3, Requirement R12 that becomes effective on 4/1/17, requiring a self-report if Tv is exceeded; the TOP-007-WECC-1 standard is pending retirement.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
for more than 30 minutes for Major WECC Transfer Paths (WECC only).		
EOP-004-3, Attachment 1 Event Type: Loss of firm load Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Loss of firm load for ≥ ≥ 300 MW for entities with previous yea 3,000 MW OR ≥ 200 MW for all other entities	EOP-004-4, Attachment 1 Event Type: Uncontrolled loss of firm load resulting from a BES Emergency Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities	To provide clarity to the Threshold for Reporting and to align with the DOE's OE-417 reporting category, language revisions were made.
EOP-004-3, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA, GOP Threshold for Reporting: Total generation loss, within one minute, of :	EOP-004-4, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA Threshold for Reporting: Total generation loss, within one minute, of:	The EOP SDT removed the reporting requirement from the GOPs to reduce redundant reporting. The BA should do the reporting given they have the generation status information.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection	Technical justification for reverting back to the value of 2,000 MW for the generation loss for the Québec Interconnection and for harmonizing with NERC EA process. 1. Generation in the Québec Interconnection is 95 % hydraulic. To be efficient, generation must operate within 80 % of its operating range. There is a large spinning reserve available at all times which aids in the recovery period after an event (ACE-Area Control Error). Historically, the recorded average ACE recovery time for a 2,000 MW loss is 5 minutes which is 3 times faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. Based on the Hydro Québec's generation loss reports, generation loss between 1,500 MW to 2,000 MW does not trig the first stage threshold of the UFLS scheme.

Standard: EOP-004-4		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
		The frequency stayed above the underfrequency limit. 3. In order to maintain the integrity of the Québec system, the RPTC SPS in Québec (Generation Rejection and Remote Load Shedding) is designed to detect abnormal or predetermined system conditions, to take corrective actions and to deliberately remove up to 1,500 MW of preselected generation from the power system. Consequently, the system is design to remain stable upon the instantaneous loss of 1,500 MW of generation. For Hydro-Québec, a generation loss of more than 2,000 MW is considered as an issue, which is make sense with previous 2,000 MW generation loss reporting requirement. 4. The EEA Level 3 alert (EOP-002) in Québec is set generally set at 2,000 MW, based on the deficiency of

Standard: EOP-004-4		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
		operating reserves and margins. Up to now, no EEA Level 3 alert has occurred in the Québec Interconnection. 5. Hydro Québec's loss of generation in first contingency (n-1) is set around 2,000 MW. Technical justification for the value of 1,400 MW for the generation loss for the ERCOT Interconnection and for harmonizing with NERC EA process. 1. ERCOT maintains a mix of operating reserves (typically 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves) available at all times, which aids in the recovery period after an event affecting Area Control Error (ACE) or frequency. ERCOT typically procures between 2,300 MW to 3,000 MW of frequency responsive reserves for all

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operating hours besides procuring additional regulation and non-spinning reserves. The Load Resources controlled by Under-Frequency relay are set to respond automatically at 59.7 Hz to provide instantaneous frequency response. Historically, the recorded average ACE recovery time for a 1,400 MW loss is less than 10 minutes, which is much faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. The design criteria for ERCOT's frequency responsive reserves is to procure adequate reserves that allow frequency to stay above the under-frequency limit for up to ERCOT's resource contingency criteria limit of 2,750 MW. 3. The EEA level 1 alert (EOP-002) in ERCOT is set at 2,300 MW of Physical Responsive Capability (PRC) which is

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		a mix of operating reserves (typically 50% Load Resources and 50% frequency responsive spinning reserves).
EOP-004-3, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	EOP-004-4, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements	The Event Analysis Program (EAP) refers to loss of off-site power as "(LOOP)". Therefore, LOOP has been added to the Threshold for Reporting to provide consistency.
EOP-004-3, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	EOP-004-4, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).	The definition of BES Element includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event Type. It could lead to confusion as to the element count for three elements contrary to design. In addition, the EAP uses the definition of "BES Facility" in its application, which could lead to additional confusion in evaluating a

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		reporting during an event. The EOP SDT revised "BES Elements" to "BES Facilities" to add clarity to the Threshold for Reporting and to align with the EAP language.
EOP-004-3, Attachment 1 Event Type: Unplanned BES control center evacuation Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	EOP-004-4, Attachment 1 Event Type: Unplanned evacuation of its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.	In the Threshold for Reporting, with the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…BES control center" to "…its BES control center."
EOP-004-3, Attachment 1 Event Type: Complete loss of voice communication capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of voice communication capability affecting a	EOP-004-4, Attachment 1 Event Type: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of Interpersonal Communication and	COM-001-2 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." And Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
BES control center for 30 continuous minutes or more.	Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.	not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."
EOP-004-3, Attachment 1 Event Type: Complete loss of monitoring capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	EOP-004-4, Attachment 1 Event Type: Complete loss of monitoring or control capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.	The language revisions to this event type provides clarity to the Threshold for Reporting and better aligns with the EAP language.

Exhibit D-2

Mapping Document for Proposed Reliability Standards EOP-005-3, EOP-006-3 and EOP-008-2

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3 Requirement R1,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		EOP-005-2 Requirement R7, is redundant to EOP-005-3 Requirement R1.
EOP-005-2, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.	EOP-005-3, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.	EOP-005-3, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.	EOP-005-3, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	would change its ability to implement its restoration plan, as follows	System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The references to unplanned permanent and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a TOP to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.	The EOP SDT revisions harmonize the use of "BES modification" and clarify the timing for unplanned permanent and planned permanent BES modifications.
EOP-005-2, Requirement R5	EOP-005-3, Requirement R5	"Implementation date" was revised to "effective date" to clarify that System

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	**R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language. Based on comments received from industry, the issue was raised that Requirement R6, as written, could be misinterpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation could result in numerous simulations having to be performed, which was outside of the intention of the drafting team. To eliminate any unintentional

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		misinterpretation of Requirement R6, it was revised to: "Each Transmission Operator shall verify through analysis of actual events, **a combination of** steady state and dynamic simulations…"
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training annually for its System Operators. This training program shall include training on	The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional*

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority.	*Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time. "The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	standard is a revision back to the original language of EOP-005-2. Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify "unique tasks."
EOP-005-2, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	EOP-005-3, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
24 hours of such changes in accordance with Requirement R13.	capabilities within 24 hours of such changes in accordance with Requirement R13.	
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.
EOP-005-2, Measure R16 **R18.** Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.	EOP-005-3, Measure R16 **R16.** Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requested to do so in accordance with Requirement R16.	simulations if requested to do so in accordance with Requirement R16.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	**1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area with Transmission Operators in other Reliability Coordinator Areas and with other Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
.	requirements of Requirement R4 and Requirement R4 Part 4.1.	
EOP-006-2, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	EOP-006-3, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	To align the requirement to the measure in Requirement R5, Part 5.1.
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of	EOP-006-3, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the	"Implementation date" was revised to "effective date" for clarity.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators, and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration.		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor = High] [Time Horizon = Real-time Operations]		
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.	EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing "data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Exhibit E-1

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-004-4

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were slightly revised to add "event reporting." The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their event reporting Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their event reporting Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Exhibit E-2

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-005-3

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three or more of the ~~r~~requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement part” and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective” and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator prior to a planned permanent BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from its Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "their" with "its." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Exhibit E-3

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-006-3

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “implementation date” with “effective date.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the annual System restoration training within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “annual” with “at least once each 15 calendar months” and by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Exhibit E-4

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standard EOP-008-2

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is a requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Exhibit F

Consideration of Issues and Directives

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Issues and Directives

Project 2015-08 Emergency Operations

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*	FERC Order Number 749	The Project 2015-02 Emergency Operations Periodic Review Team (EOP PRT), as well as the Project 2015-08 Emergency Operations Standards Drafting Team (EOP SDT) determined (through conducted outreach and comment questions/responses during postings of periodic review templates, the project SAR, and project postings) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the Transmission Operator (TOP), Transmission Owner (TO), and the Distribution Provider (DP). A rationale box was added to EOP-005-3, Rquirement R9 to clarify "unique tasks." **Rationale:** The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.
Clarify when system changes will trigger a requirement to update restoration plans. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for updating restoration	FERC-NERC-Regional Entity Joint Review of Restoration	The Project 2015-08 EOP SDT revised EOP-005-3, Requirement R4 and the requirement parts. The references to unplanned permanent and planned permanent BES modifications that will change the ability to implement the Reliability Coordinator (RC)-approved restoration plan are intended to require a TOP to

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
plans for all system modifications that would change the implementation of an entity's restoration plan for an extended period of time, not just permanent or planned system modifications. In considering these measures, the kinds of events that may warrant an update to the system restoration plan should be identified, taking into account the length of time the system is affected, as well as the overall objective of ensuring that restoration plans are generally flexible enough so that system modifications can be addressed without continuous updates.	and Recovery Plans. **Section IV.E**	update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RC's ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.
Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits.6 In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new	FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. **Section IV.G**	The EOP SDT discussed the recommendation to address the "…need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably…" The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan, these also have to be submitted to the RC for review, 3) include within its operations training program annual System restoration training

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
blackstart generator location or on redefinition of a cranking path).		for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC 1) has to review its restoration plan within 13 calendar months of the last review, 2) has to review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) has to review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed to system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System, and the RC is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, that both entities are continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation.
Operator training: Exercises on transferring control back to the balancing authority. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to	FERC-NERC-Regional Entity Joint Review of	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised in EOP-005-3, Requirement R1, Part 1.9 to the standard: "Processes for

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
address system restoration training and drilling for transitioning from transmission operator island control to balancing authority ACE/AGC7 control.	Restoration and Recovery Plans. **Section IV.H.**	transferring operations ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Exhibit G

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standards EOP-004-4, EOP-005-3, EOP-006-3 and EOP-008-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Standard Drafting team ("SDT") members is included in Exhibit H.

II. Standard Development History

A. Standard Authorization Request Development

Project 2015-08 – Emergency Operations was initiated in direct relation to recommendations provided by the Project 2015-02 – Emergency Operations Periodic Review Team ("EOP PRT") to revise a subset of Emergency Operations Reliability Standards[3] reviewed in that project. Specifically, the EOP PRT developed a recommendation to address an outstanding Commission directive in Order No. 749.[4]

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

3 The EOP PRT reviewed Reliability Standards EOP-004-2, EOP-005-2, EOP-006-2, and EOP-008-1 to evaluate whether the requirements are clear and unambiguous.

4 Order No. 749, *System Restoration Reliability Standards*, 134 FERC ¶ 61, 215, 76 Fed. Reg. 16, 277 (2011) at P 24.

The Standards Authorization Request ("SAR") for Project 2015-08 was initially posted on July 15, 2015 for a 30-day informal comment period from July 21, 2015 through August 19, 2015. The SAR was accepted by the Standards Committee on June 15, 2016.

B. First Posting - Comment Period, Initial Ballots and Non-binding Polls

Proposed Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2, the associated Implementation Plan, Violation Risk Factors ("VRFs"), and Violation Severity Levels ("VSLs") were posted for a 45-day formal comment period from June 30, 2016 through August 15, 2016, with parallel Initial Ballots and a Non-binding Polls of the proposed VRFs and VSLs for proposed Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2 held during the last 10 days of the comment period from August 4, 2016 through August 15, 2016. The Initial Ballot for proposed Reliability Standard EOP-005-3 received 80.45% quorum, and 52.90% approval. The Initial Ballot for proposed Reliability Standard EOP-006-3 received 81.14% quorum, and 66.87% approval. The Initial Ballot for proposed Reliability Standard EOP-008-2 received 80.79% quorum, and 84.13% approval. The Non-binding Poll for proposed Reliability Standard EOP-005-3 received 78.01% quorum and 55.74% of supportive opinions. The Non-binding Poll for proposed Reliability Standard EOP-006-3 received 79.14% quorum and 69.93% of supportive opinions. The Non-binding Poll for proposed Reliability Standard EOP-008-2 received 79.36% quorum and 85.33% of supportive opinions. There were 64 sets of responses, including comments from approximately 141 different individuals and approximately 75 companies, representing 9 of the 10 industry segments.[5]

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5 NERC, *Consideration of Comments*, Project 2015-08 Emergency Operations (EOP-005-3, EOP-006-3, and EOP-008-2), (October 25, 2016), *available at* http://www.nerc.com/pa/Stand/Project%20201508%20Emergency%20Operations/Project_2015-08_Consideration_of_Comments_October_2016.pdf.

C. First Posting- Comment Period, Initial Ballot and Non-binding Poll

During the first posting of Proposed Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2, the SDT also began to develop proposed Reliability Standard EOP-004-4 in response to recommendations provided by stakeholders and the EOP PRT. Proposed Reliability Standard EOP-004-4, the associated Implementation Plan, VRFs and VSLs were posted for a 45-day formal comment period from July 25, 2016 through September 8, 2016, with parallel Initial Ballot and a Non-binding Poll of the proposed VRFs and VSLs for proposed EOP-004-4 held during the last 10 days of the comment period from August 30, 2016 through September 8, 2016. The Initial Ballot for proposed Reliability Standard EOP-004-4 received 82.75% quorum, and 80.32% approval. The Non-binding Poll for proposed Reliability Standard EOP-004-4 received 81.56% quorum and 81.19% of supportive opinions. There were 53 sets of responses, including comments from approximately 134 different individuals and approximately 47 companies, representing 8 of the 10 industry segments.[6]

D. Second Posting - Comment Period, Additional Ballots and Non-binding Polls

Proposed Reliability Standards EOP-005-3 and EOP-006-3 were posted for an additional 45-day formal comment period from October 26, 2016 through December 9, 2016, with parallel Additional Ballots for proposed EOP-005-3 and EOP-006-3 and Non-binding Polls of the proposed VRFs and VSLs held during the last 10 days of the comment period from November 30, 2016 through December 9, 2016. The Additional Ballot for proposed Reliability Standard EOP-005-3 reached quorum at 80.97% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 76.93% of the voters. The Additional Ballot for

[6] NERC, *Consideration of Comments*, Project 2015-08 Emergency Operations (EOP-004-4) (November 2016), *available at* http://www.nerc.com/pa/Stand/Project%20201508%20Emergency%20Operations/Project_2015_08_EOP_004_Consideration_of_Comments_November_2016.pdf.

proposed Reliability Standard EOP-006-3 reached quorum at 82.71% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 77.17% of the voters. The Non-binding Poll for proposed Reliability Standard EOP-005-3 received 80.28% quorum and 75.69% of supportive opinions. The Non-binding Poll for proposed Reliability Standard EOP-006-3 received 81.88% quorum and 75.64% of supportive opinions. There were 53 sets of responses, including comments from approximately 44 different individuals and approximately 41 companies, representing 9 of the 10 industry segments.[7]

E. Second Posting - Comment Period, Additional Ballot and Non-binding Poll

Proposed Reliability Standard EOP-004-4 was posted for an additional 45-day comment period from November 18, 2016 through January 6, 2017, with a parallel Additional Ballot for proposed EOP-004-4 and a Non-binding Poll of the VRFs and VSLs held during the last 10 days of the comment period from December 28, 2016 through January 6, 2017.[8] The Additional Ballot for proposed Reliability Standard EOP-004-4 reached quorum at 79.71% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 93.55% of the voters. The Non-binding Poll for proposed EOP-004-4 received 79.25% quorum and 95.05% of supportive opinions. There were 38 sets of responses, including comments from approximately 33 different individuals and approximately 31 companies, representing 8 of the 10 industry segments.[9]

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[7] NERC, *Consideration of Comments*, Project 2015-08 Emergency Operations (EOP-005-3 and EOP-006-3) (December 2016), *available at* http://www.nerc.com/pa/Stand/Project%20201508%20Emergency%20Operations/2015-08_Consideration_of_Comments_122816.pdf.

[8] The Additional ballot period for proposed Reliability Standard EOP-004-4 and the Non-binding Poll for the associated VRFs and VSLs were extended to January 9, 2017 to reach quorum.

[9] NERC, *Consideration of Comments*, Project 2015-08 Emergency Operations (EOP-004-4) (January 2017), *available at* http://www.nerc.com/pa/Stand/Project%20201508%20Emergency%20Operations/2015-08_Consideration_of_Comments_012317.pdf.

F. Final Ballot

Proposed Reliability Standard EOP-008-2 was posted for a 10-day final ballot period from November 30, 2016 through December 9, 2016. The final ballot for proposed Reliability Standard EOP-008-2 and associated documents reached quorum at 93.36% of the ballot pool, and the proposed standard received sufficient affirmative votes for approval, receiving support from 93.17% of the voters.[10]

G. Final Ballots

Proposed Reliability Standards EOP-005-3 and EOP-006-3 were posted for a 10-day final ballot period from December 28, 2016 through January 6, 2017. The final ballot for proposed Reliability Standard EOP-005-3 and associated documents reached quorum at 91.29% of the ballot pool, and the proposed standard received sufficient affirmative votes for approval, receiving support from 83.65% of the voters.[11] The final ballot for proposed Reliability Standard EOP-006-3 and associated documents reached quorum at 91.86% of the ballot pool, and the proposed standard received sufficient affirmative votes for approval, receiving support from 80.56% of the voters.[12]

H. Final Ballot

Proposed Reliability Standard EOP-004-4 was posted for a 10-day final ballot period from January 24, 2017 through February 2, 2017. The final ballot for proposed Reliability Standard EOP-004-4 and associated documents reached quorum at 84.71% of the ballot pool, and the

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[10] NERC, Ballot Results (EOP-008-2), *available at* https://sbs.nerc.net/BallotResults/Index/171.

[11] NERC, Ballot Results (EOP-005-3), *available at* https://sbs.nerc.net/BallotResults/Index/188.

[12] NERC, Ballot Results (EOP-006-3), *available at* https://sbs.nerc.net/BallotResults/Index/189.

proposed standard received sufficient affirmative votes for approval, receiving support from 93.80% of the voters.[13]

I. Board of Trustees Adoption

Proposed Reliability Standards EOP-004-4, EOP-005-3, EOP-006-3 and EOP-008-2 were adopted by the NERC Board of Trustees on February 9, 2017.[14]

[13] NERC, Ballot Results (EOP-004-4), *available at* https://sbs.nerc.net/BallotResults/Index/192.

[14] NERC, *Board of Trustees Agenda Package*, Agenda Item 4b (Project 2015-08 Emergency Operations (EOP-004-4, EOP-005-3, EOP-006-3 and EOP-008-2), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_February_9_2017_Meeting_Agenda_Package.pdf.

Complete Record of Development

Program Areas & Departments > Standards > Project 2015-08 Emergency Operations

Project 2015-08 Emergency Operations

Related Files | 2015-02 Periodic Review of Emergency Operations

Status
Final ballots for the standards related to **Project 2015-08 Emergency Operations** have concluded and the voting results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

EOP-004-4 - Event Reporting concluded on **February 2, 2017.**

EOP-005-3 - System Restoration from Blackstart Resources and **EOP-006-3 - System Restoration Coordination** concluded on **January 6, 2017.**

EOP-008-2 – Loss of Control Center Functionality concluded on **December 9, 2016**.

Background
The Emergency Operations Periodic Review Team (**Project 2015-02**) performed a comprehensive review of a subset of Emergency Operations Standards (EOP-004, EOP-005, EOP-006 and EOP-008) to evaluate, for example, whether the requirements are clear and unambiguous. The Periodic Review included background information, along with any associated worksheets or reference documents, to guide a comprehensive review that resulted in the following recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 – (1) Revise the standard and (2) retire Requirements Parts R1.2, R1.3, and R1.4; and
- EOP-008-1 – Revise the standard.

The four NERC Reliability Standards in the Periodic Review project concerned methodologies for restoring, reporting, and communicating Emergencies.

Standards Affected - EOP-004-2 - Event Reporting **| EOP-005-2 -** System Restoration from Blackstart Resources **| EOP-006-2 -** System Restoration Coordination **| EOP-008-1 -** Loss of Control Center Functionality

Purpose / Industry Need
Implementation of revisions and retirements recommended by the EOP Standard Drafting Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing the outstanding directive from FERC Order No. 749.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft EOP-004-4 Clean **(111)** | Redline to Last Posted **(112)** | Redline to Last Approved **(113)** Implementation Plan Clean **(114)** | Redline to Last Posted **(115)** **Supporting Materials** Mapping Document Clean **(116)** | Redline to Last Posted **(117)** VRF/VSL Justification Clean **(118)** | Redline to Last Posted **(119)**	Final Ballot Info **(120)** Vote	01/24/17 – 02/02/17	Ballot Results **(121)**	
Final Drafts EOP-005-3 Clean **(93)** | Redline to Last Posted **(94)** | Redline to Last Approved **(95)** EOP-006-3 Clean **(96)** | Redline to Last Posted **(97)** | Redline to Last Approved **(98)** Implementation Plan Clean **(99)** | Redline to Last Posted **(100)** **Supporting Materials** Mapping Document Clean **(101)** | Redline to Last Posted **(102)**	Final Ballots Info **(108)** Vote	12/28/16 – 1/06/17	Ballot Results EOP-005-3 **(109)** EOP-006-3 **(110)**	

VRF/VSL Justifications EOP-005-3 Clean **(103)** | Redline to Last Posted **(104)** EOP-006-3 Clean **(105)** | Redline to Last Posted **(106)** Consideration of Issues and Directives **(107)**				
Final Draft EOP-008-2 Clean **(82)** | Redline to Last Posted **(83)** | Redline to Last Approved **(84)** Implementation Plan Clean **(85)** | Redline to Last Posted **(86)** **Supporting Materials** Mapping Document Clean **(87)** | Redline to Last Posted **(88)** VRF/VSL Justification Clean **(89)** | Redline to Last Posted **(90)**	Final Ballot Info **(91)** Vote	11/30/16 – 12/09/16	Ballot Results **(92)**	
Draft 2 EOP-004-4 Clean **(67)** | Redline to Last Posted **(68)** Implementation Plan Clean **(69)** | Redline to Last Posted **(70)** **Supporting Materials** Unofficial Comment Form **(71)** Mapping Document Clean **(72)** | Redline to Last Posted **(73)** VRF/VSL Justification Clean **(74)** | Redline to Last Posted **(75)** Draft Reliability Standard Audit Worksheet (RSAW)	Additional Ballot and Non-binding Poll Info **(76)** Vote	12/28/16 – 1/06/17 (Extended to 1/09/17 to meet quorum)	Ballot Results **(77)** Non-binding Poll Results **(78)**	
	Comment Period Info **(79)** Submit Comments	11/18/16 – 1/06/17 (Extended to 1/09/17 due to ballot extension)	Comments Received **(80)**	Consideration of Comments **(81)**
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	12/02/16 - 1/06/17 (Extended to 1/09/17 due to ballot extension)		
Draft 2 EOP-005-3 Clean **(44)** | Redline to Last Posted **(45)** EOP-006-3 Clean **(46)** | Redline to Last Posted **(47)** Implementation Plan Clean **(48)** | Redline to Last Posted **(49)** **Supporting Materials** Mapping Document Clean **(50)** | Redline to Last Posted **(51)**	Additional Ballots and Non-binding Polls Updated Info **(58)** Info **(59)** Vote	11/30/16 – 12/09/16	Ballot Results EOP-005-3 **(60)** EOP-006-3 **(61)** Non-binding Polls Results EOP-005-3 **(62)** EOP-006-3 **(63)**	
	Comment Period Info **(64)**	10/26/16 – 12/09/16	Comments Received **(65)**	Consideration of Comments **(66)**

Unofficial Comment Form (Word) **(52)** Consideration of Issues and Directives **(53)** Added 11/1/16 VRF/VSL Justifications EOP-005-3 Clean **(54)** | Redline to Last Posted **(55)** EOP-006-3 Clean **(56)** | Redline to Last Posted **(57)** Draft Reliability Standard Audit Worksheets (RSAWs) EOP-005-3 EOP-006-3	Submit Comments			
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	11/08/16 - 12/09/16		
Draft 1 EOP-004-4 Clean **(31)** | Redline to Last Approved **(32)** Implementation Plan **(33)** **Supporting Materials** Unofficial Comment Form (Word) **(34)** Mapping Document **(35)** VRF/VSL Justification **(36)** Draft Reliability Standard Audit Worksheet (RSAW)	Initial Ballot and Non-binding Poll Updated Info **(37)** Info **(38)** Vote	08/30/16 - 09/08/16	Ballot Results **(39)** Non-binding Poll Results **(40)**	
	Comment Period Info **(41)** Submit Comments	07/25/16 - 09/08/16	Comments Received **(42)**	Consideration of Comments **(43)**
	Join Ballot Pools	07/25/16 - 08/23/16		
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	08/18/16 - 09/08/16		
Draft 1 EOP-005-3 Clean **(8)** | Redline to Last Approved **(9)** EOP-006-3 Clean **(10)** | Redline to Last Approved **(11)** EOP-008-2 Clean **(12)** | Redline to Last Approved **(13)**	Initial Ballots and Non-binding Polls Updated Info **(20)** Info **(21)** Vote	08/04/16 - 08/15/16	Ballot Results EOP-005-3 **(22)** EOP-006-3 **(23)** EOP-008-2 **(24)** Non-binding Polls Results EOP-005-3 **(25)**	

Implementation Plan **(14)** **Supporting Materials** Unofficial Comment Form (Word) **(15)** VRF/VSL Justifications EOP-005-3 **(16)** EOP-006-3 **(17)** EOP-008-2 **(18)** Mapping Document **(19)** Draft Reliability Standard Audit Worksheets (RSAWs) EOP-005-3 EOP-006-3 EOP-008-2			EOP-006-3 **(26)** EOP-008-2 **(27)**	
	Comment Period Info **(28)** Submit Comments	06/30/16 - 08/15/16	Comments Received **(29)**	Consideration of Comments **(30)**
	Join Ballot Pools	06/29/16 - 07/28/16		
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	07/08/16 - 08/15/16		
SAR **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	07/21/15 - 08/19/15	Comments Received **(6)**	Consideration of Comments **(7)**
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	07/21/15 - 08/04/15		

Nomination Form

Project 2015-08 Emergency Operations Standards Drafting Team

Please return this form as soon as possible, but no later than **8:00 p.m. Eastern, Tuesday, August 4, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, please contact Laura Anderson.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings, as well as participate in all the team meetings held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team efforts is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2015-08 Emergency Operations

The purpose of this project is to implement the recommendations of the Periodic Review Team (PRT) that resulted from the PRT's review of a subset of Emergency Operations (EOP) Standards. The Periodic Review comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous. The Periodic Review included developing a recommendation based upon the language of Federal Energy Regulatory Commission (Commission) Order no. 749[1] as follows:

> *"[N]ERC, in its comments about the term, states that it "could promote the development of a guideline to aid registered entities in complying with Requirement R11." The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*[2]

[1] *System Restoration Reliability Standards*, 134 FERC ¶61,215 (2011) (Order No. 749).
[1] *Id.* at P24.
[2] *Id.* at P24.

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 – (1) Revise the standard and (2) retire Requirements Parts R1.2, R1.3, and R1.4; and
- EOP-008-1 – Revise the standard.

Standards affected: EOP-004-2, EOP-005-2, EOP-006-2 and EOP-008-1

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise with Emergency Operations methodologies for program planning, program training, restoring, reporting, and communicating across the United States and/or Canada.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	

If you previously worked on any NERC drafting team please identify the team(s):
☐ No prior NERC SAR or standard drafting team.
☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ ERCOT ☐ FRCC ☐ MRO	☐ NPCC ☐ RFC ☐ SERC	☐ SPP ☐ WECC ☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[3] in which you have current or prior expertise:

[3] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

☐ Balancing Authority ☐ Compliance Enforcement Authority ☐ Distribution Provider ☐ Generator Operator ☐ Generator Owner ☐ Interchange Authority ☐ Load-serving Entity ☐ Market Operator ☐ Planning Coordinator	☐ Transmission Operator ☐ Transmission Owner ☐ Transmission Planner ☐ Transmission Service Provider ☐ Purchasing-selling Entity ☐ Reliability Coordinator ☐ Reliability Assurer ☐ Resource Planner

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

Standards Announcement

Project 2015-08 Emergency Operations

Standard Drafting Team Nomination Period Open through August 4, 2015

Now Available

Nominations are being sought for standard drafting team members through **8 p.m. Eastern, Tuesday, August 4, 2015.**

Use the electronic form to submit a nomination. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings, as well as participate in all the team meetings held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the drafting team sets forth. Drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the drafting team efforts is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Previous drafting team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

2015-08 Emergency Operations

The purpose of this project is to implement the recommendations of the Periodic Review Team (PRT) that resulted from the PRT's review of a subset of Emergency Operations (EOP) Standards. The Periodic Review comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous. The Periodic Review included developing a recommendation based upon the language of Federal Energy Regulatory Commission (Commission) Order no. 749[1] as follows:

> "[N]ERC, in its comments about the term, states that it "could promote the development of a guideline to aid registered entities in complying with Requirement R11." The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry

determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."[2]

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

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- EOP-005-2 – Revise the standard;
- EOP-006-2 – (1) Revise the standard and (2) retire Requirements Parts R1.2, R1.3, and R1.4; and
- EOP-008-1 – Revise the standard.

Next Steps

The Standards Committee is expected to begin appointing members to the standard drafting team for Project 2015-08 in August 2015. Nominees will be notified shortly after they have been appointed to the standard drafting team.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2015-08 Emergency Operations (EOP-004-2, EOP-005-2, EOP-006-2, EOP-008-1)		
Date Submitted:	July 8, 2015		
SAR Requester Information			
Name:	David McRee, Chair of Project 2015-02 Emergency Operations Periodic Review Team		
Organization:	Duke Energy		
Telephone:	704-382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standards		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The NERC Standard Processes Manual (see Section 13) obligates NERC to conduct Periodic Reviews of standards at a minimum interval of every ten years, with ANSI approved standards at five year intervals. NERC has responded to regulatory and industry guidance by incorporating into its Periodic Review process both principles of Results-based standards drafting and a review of each standard in relation to other standards to eliminate duplicative requirements. Additionally, Periodic Reviews evaluate whether each standard is clear, concise, and technically sound given current technologies and system conditions, whether any regulatory directives require specific changes to the standard, and whether requirements

SAR Information
that do little to ensure the reliability of the Bulk-Power System should be eliminated. Periodic Reviews also consider previously-captured stakeholder-identified issues pertaining to the affected standards. The Emergency Operations Periodic Review Team (EOP PRT) has reviewed and developed a recommendation based upon the language of Federal Energy Regulatory Commission (Commission) Order no. 749[1], as follows: *"[N]ERC, in its comments about the term, states that it "could promote the development of a guideline to aid registered entities in complying with Requirement R11." The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*[2]
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to appoint a Standard Drafting Team (SDT) to address the directive of the Commission Order No. 749, Paragraph 24, for EOP-005-2, System Restoration from Blackstart Resources and to implement the recommendations of the Project 2015-02 EOP PRT to revise EOP-004-2, EOP-005-2, EOP-006-2, and EOP-008-1; as well as to implement the recommended requirement retirements in EOP-004-2 and EOP-006-2.
Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and Results-based Reliability standards to address the recommendations of the EOP PRT.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations of the EOP PRT and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standards' requirements and measures

[1] *System Restoration Reliability Standards*, 134 FERC ¶61,215 (2011) (Order No. 749).
[2] *Id.* at P24.

SAR Information
and shall address Commission Order no. 749, Paragraph 24, for EOP-005-2, System Restoration from Blackstart Resources.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also 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.)
The SDTs execution of this SAR requires the SDT to address each recommendation of the EOP PRT, as well as the Commission directive in Order No. 749, Paragraph 24 for EOP-005-2, System Restoration. The SDTs execution of this SAR would, in addition, address the EOP PRT's recommendations of retirements to requirements under Paragraph 81 criteria. The reliability assessment and justification is also set forth in the final recommendations of the EOP PRT. The Commission Order, Paragraph 24 (for EOP-005-2) is incorporated in its entirety into this SAR, so as not to unnecessarily repeat or paraphrase the substance of the Order. There are no market interface impacts resulting from the standard action on the implementation of the Project 2015-02, EOP PRT's recommendations.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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.

Reliability Functions		
☐	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	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 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?	Enter (yes/no)
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 Standards	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2015-08 Emergency Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **8:00 p.m. Eastern, Wednesday, August 19, 2015**.

If you have questions please contact Laura Anderson via email or by telephone at (404) 446-9671.

Background Information

This posting is soliciting informal comment.

On February 3, 2015, the Standards Committee appointed the Project 2015-02 Emergency Operations Periodic Review Team (EOP PRT) and tasked them to review the following standards:

- EOP-004-2 — Event Reporting;
- EOP-005-2 — System Restoration from Blackstart Resources;
- EOP-006-2 — System Restoration Coordination; and
- EOP-008-1 — Loss of Control Center Functionality.

Based on this review, the EOP PRT developed a set of recommendations for EOP-004-2, EOP-005-2, EOP-006-2, and EOP-008-1. The EOP PRT recommendations were posted for a 45-day comment period from March 27, 2015 through May 11, 2015.

The EOP PRT carefully reviewed and considered the comments received during the posting period and, based on stakeholder comments, made revisions to the initial recommendations. To support consideration and implementation of these recommendations, the EOP PRT developed a new Standards Authorization Request (SAR). Many improvements suggested by stakeholders during the comment period were incorporated into the final recommendations.

The recommendations of the EOP PRT are attached to the SAR (Periodic Review Templates). The recommendations of the EOP PRT are as follows:

- EOP-004-2 – (1) Revise the standard and attachement and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 – (1) Revise the standard and (2) retire Requirements Parts R1.2, R1.3, and R1.4; and
- EOP-008-1 – Revise the standard.

Additional documents developed to support the Project 2015-02 team's recommendations have been posted to the 2015-02 EOP PRT project page, including: 1) the EOP PRT's consideration of comments on the draft recommendations; 2) Department of Energy OE-417 Comparison of Reporting; 3) and Standards Independent Experts Review Project.

The EOP PRT has reviewed and developed a recommendation based upon the language of Federal Energy Regulatory Commission (Commission) Order no. 749[1], as follows:

> *"[N]ERC, in its comments about the term, states that it "could promote the development of a guideline to aid registered entities in complying with Requirement R11." The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*[2]

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. The scope of this project includes:

- Implement the recommendations of the periodic review team related to the following standards:
  - EOP-004-2
  - EOP-005-2
  - EOP-006-2
  - EOP-00801
- Improve quality, relevance and clarity of the standards
- Bring standards into Results-Based format
- Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel

Do you agree with this scope? If not, please explain.

☐ Yes

☐ No

Comments:

[1] *System Restoration Reliability Standards*, 134 FERC ¶61,215 (2011) (Order No. 749).

[1] *Id.* at P24.

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

☐ Yes
☐ No
Comments:

3. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance:

☐ Yes
☐ No
Comments:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice:

☐ Yes
☐ No
Comments:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

☐ Yes
☐ No
Comments:

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations Standard Authorization Request

Informal Comment Period Open through August 19, 2015

Now Available

A 30-day informal comment period for the **2015-08 Emergency Operations** Standard Authorization Request (SAR) is open through **8 p.m. Eastern, Wednesday, August 19, 2015.**

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9761.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2009-02 Real-time Monitoring and Analysis Capabilities SAR

Description

Start Date 7/16/2015

End Date 8/17/2015

Associated Ballots

Survey Questions

1. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Yes

No

Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Responses By Question

1. Do you agree with the proposed scope for Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We agree with the need to establish the requirements for real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations. However, we believe such requirements do not rise up to the level of Reliability Standards, whose objective is to drive the proper behaviors that contribute to reliability.

We believe real-time monitoring and analysis capabilities are the "one-off" type that is required for performing a registered entity's functions. Such capabilities need to be provided and tested at the organization certification stage, and in subsequent verification stages. Another example of this type of requirement is the provision of redundant communication facilities, or the installation of disturbance monitoring devices.

Therefore, we do not support this SAR, and propose that the requirements for providing the real-time monitoring and analysis capabilities be stipulated in the concerned functional entities' organization certification requirement.

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6

Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

The NSRF is aware of the Commission directives and past outage reports that have set the foundation for this project. Taken singularly (looking at these objectives, only) this Project should be rather straight forward. But as the SDT knows, the newly developed Requirements will be in addition to the real-time responsibilities that (System) operators have currently, in maintaining a balanced and secure system.

The NSRF wishes to remind the SDT that awareness (within Situational Awareness) should not turn into Situational Assurance (beyond a doubt). That *awareness* is "*knowing*" that something exist that may impact you and not necessarily having an *in depth understanding* of the root cause and effect of the situation. As an example, a TOP has a 345kV line trip and lock out. The TOP should have an *in depth understanding* of how the megawatt flows of their system will change when this lock out occurs. The impact BA Area does not need to *know* much beyond that the line has tripped, but rather needs the awareness that they may be called upon to help reconfigure their system (re-dispatch generation, shed load, etc.).

All Requirements (present and future) cannot remove the possibility of human error. A contributing factor to human error is data overload (ie, alarms [actual and false] communications [phone call, radio call, blast calls], processing this tremendous amount of information, having information constantly in a state of change and being compliant with ALL currently enforceable Standards. Note that System Operators have a higher tendency to make mistakes when their systems are stressed and usually in an emergency condition (either a capacity or transmission emergency). Not that their tools failed them but rather the most critical element or system condition wasn't mitigated first. The SDT must remain aware to *complexity creep* and look at ALL real-time operator responsibilities when developing this project and that adding new responsibilities may be detrimental to system reliability..

The NSRF looks forward to working with the SDT on this Project.

Note: We have progressed and are now aware of systems and conditions since the 2003 Blackout. Please consider this. Tools should be used as a "control" within an entity's Risk Assessment.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NA - Not Applicable

Group Information

Group Name: Standards Review Committee (SRC)

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Matthew Goldberg	ISO-NE	NPCC	2
Christina Bigelow	ERCOT	TRE	2
Terry Bilke	MISO	MRO	2
Al Dicaprio	PJM	RFC	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter
Kathleen Goodman

Segment
2

Entity
ISO New England, Inc.

Region(s)
NA - Not Applicable

Selected Answer: No

Answer Comment:

This proposed project appears to be well-suited for a guideline document as opposed to a Standard. As written, the SAR appears to intend to write a "how" not "what" Standard (*i.e.*, it does not appear to be a results-based standard). The SRC believes that the existing Standards (*i.e.*, IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (*i.e.*, without defining the "how"), which is appropriate. In the alternative, this could be considered a process to be used for Certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standards Requirements.

The SRC notes that the tools available to operators have progressed well beyond those available in 2003. If defined tools would have been hardcoded in a standard at that time, it would have limited focus and investment to those things that were in the standard. Further, expanding on our point above, the SRC believes that the "what" regarding tools is more appropriately captured in the certification expectations for BAs, RCs, and TOPs. Additionally, it would be appropriate for Regions to evaluate tools as part of the Registered Entity's Inherent Risk Assessment (IRA). This would include the scope of tools, backups, etc. and would provide an adaptable approach that would encourage continuous improvement.

Additionally, the SRC recommends that NERC coordinate with the NATF to encourage inclusion of an ongoing "care and feeding" of tools evaluation and information sharing in their efforts with the provision that they make information on good practices available to the wider NERC community so that non-members can learn from the innovation of others.

Finally, to avoid these issues in the future and to support communicating to FERC when a Standard is not needed and another tool is more suitable, the SRC suggests that future SARs be voted on by industry to determine whether they should proceed as a Standards project or another means is a more appropriate method through which to achieve the SAR's objective.

Document Name:

Likes: 1 Tri-State G and T Association, Inc., 1,3,5, Banuelos Sergio

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	**Segment**
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

The SAR has the "NEW" Standard box checked but not the "Revision to existing Standard" box. Based on the statement below from the SAR,
FirstEnergy feels the "Revision to existing Standard" should be checked also so other Standards can be included if necessary..

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the SRC's comments regarding the proposed SAR, but - should the SAR proceed - would urge the SDT to ensure that the focus remains on what needs to be done - not how it should be done.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment:

How does NERC's Project 2009-02 differ from the work about to begin in the NERC Synchrophasor Measurements Subcommittee (SMS)? Should this project be part of SMS? In my mind ther is a great deal of overlap between the new SMS and Project 2009-02 and to a large extent, Project 2009-2 is dependent on the work to be done by SMS. Entergy recommend a delay or no vote on this project until SMS work is completed.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2009-02

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10

David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

Suggest revising the Purpose to make it more encompassing. Suggest the following wording:

To establish situational awareness capabilities with results-based requirements for monitoring and analysis used by System Operators in support of reliable Real-time System operations.

The concepts being proposed in the scope of the SAR can be realized by revising the appropriate TOP and IRO standards by either revising existing requirements, or adding requirements. A new standard may not be necessary. Therefore, the SAR should provide the Drafting Team with the flexibility to add requirements to IRO-010-2 and TOP-003. For example, Requirement R2 in IRO-010-2 stipulates that:

“R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.”

This requirement satisfies both the posted Purpose of the SAR:

“To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.”

and our suggested revision above.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: Yes

Answer Comment:

We agree with the overall scope of the SAR. However, we do have a two concerns to address.

First, the SAR indicates that it will address all recommendations of the RTBPTF while the SAR Justification indicates that not all recommendations will be implemented. If by “addressing the recommendations” the SAR indicates that recommendation will considered based on its merits, we agree. Furthermore, we agree with the disposition of the vast majority of the recommendations as written in the SAR justification.

Second, if a “common understanding of *monitoring*” means a definition will be developed, we caution the drafting team to conduct a complete wholesale review of all NERC reliability standards to be sure the definition would not change the meaning of other requirements or cause confusion on applicability of the definition.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1,3 - NPCC

Selected Answer: Yes

Answer Comment:

Hydro One Networks Inc. would like to provide the following additional recommendations for the SDT’s consideration:

1. The effort required to capture activities/best practices the majority of entities have already employed may be of value;

2. The standard does not appear to deliver the intended future direction for system monitoring and ways to achieve this;

3. By the nature and competitiveness of the MS industry, providers will continue to develop and offer new functionalities that may or may not be desirable for every entity. The effort would be better suited to standardize requirements and allow for the industry to catch up to a common standard. In other words, this effort would provide minimal benefit for entities that already have a modern EMS and for others a large change to meet current requirements;

4. The goal should be to level-off the playing field and have all entities reach the same level of monitoring first.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
John Allen	City Utilities of Springfield	SPP	1,4
Jason Smith	Southwest Power Pool Inc	SPP	2
Kevin Giles	Westar Energy,Inc.	SPP	1,3,5,6
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5

Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Jess Gray	Omaha Public Power District	MRO	3
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Sing Tay	Oklahoma Gas and Elecric, Inc	SPP	1,3,5,6
Scott Williams	City Utilities of Springfield	SPP	1,4

Voter Information

Voter
Shannon Mickens

Segment
2

Entity
Southwest Power Pool, Inc. (RTO)

Region(s)
SPP

Selected Answer: No

Answer Comment:

Our review team believes that the standards process has resulted in a mature set of Reliability Standards that already fully address FERC Order 693. With that being said, we feel that there is no need for continuing efforts on this project for the fear of redundancy. We have concerns that the scope of the SAR could result in requirements that are redundant to other existing Standards and inappropriately set minimum capabilities based on a list of best practices. The SAR scope seems to focus on quality of information for entities in carrying out their adherence to other Standards. Additionally, we feel that perhaps the documentation of the entities capabilities should be captured in either the Rules of Procedure or other certification or registration procedures rather than in a Reliability Standard. Another option would be to include descriptions or clarification of those capabilities within the supporting documentation of the other Standards.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE noticed communicating results was not part of the SAR. Effective communications is part of situational awareness and can directly be related to the quality of information being provided as well as awareness of key monitoring and analysis capabilities. Monitoring and analysis capabilities should include communicating results to all entities requiring information. Is the SDT considering this type of communication? Texas RE is concerned the scope seems narrow. Has the SDT or NERC clearly identified all the recommendations and FERC directives have been thoroughly covered by the changes in all the relative Standards?

Texas RE acknowledges that FERC Order No. 693 mentioned that it did not wish to identify specific tools, but rather minimum capabilities. There are, however, standard industry tools for monitoring. Texas RE recommends the SDT consider making certain tools mandatory. Tools determine the status of reliability of the system. It seems as if the industry sees the need to call specific types of tools out but does not want the compliance aspects associated with the tools. State estimator and contingency analysis tool are extremely common utility practices to help ensure reliability. Is there a part of the BES that is not being monitored by a State Estimator or Contingency Analysis tool?

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

Tri-State Generation and Transmission supports the comments submit by the Standards Review Committee (SRC).

In addition, Tri-State also would like to add the following. Tri-State recognizes that Real-time situational awareness might have been a factor of the 2003 Northeast blackout and the 2011 Southwest blackout, however we believe that over the past four years there has been significant developments and improvement in the tools that operators have available particularly within the WECC region. Additionally, the recent bifurcation in the WECC region and the subsequent creation of a standalone Reliability Coordinator has led to significant improvements in regional coordination, operations, and overall system visibility. We believe the new TOP-003-1 standard directly addresses the 'what' leaving the 'how' up to the individual utility, specifically:

Requirement R10 for Monitoring power System data in Real-time (and TOP-003-3)
Requirement R13 for Determining the current state of the BES and Evaluating the impact of 'what if' events on the current state of the BES
Requirement R19 for Exchanging power System data in Real-time

Tri-State does not agree with the SAR and its intentions but should the SAR proceed we urge the SDT to better define the intentions of the SAR. Specifically Tri-State does not understand how the SDT intends to quantify acceptable "quality" without resulting in a subjective audit? Also what is included in the term "analysis capabilities" and how will these items be sufficiently quantified to allow for a consistent audit approach across the various Regional Entities?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

In general, BPA agrees with the scope of the SAR, and conceptually with the effort to tie performance based metrics to real time situational awareness. BPA also agrees with the SAR DT, that the scope of the Project 2009-02 should avoid prescriptive assumptions regarding the implementation of real time tools by a specific entity.

As noted in the SAR Justification, real time situational awareness is closely associated with the pending definition of Real-time Assessment. BPA suggests that the concept of providing operators with notification of Availability, as described by the SAR DT, is already implied by the pending requirements in proposed TOP-001-3 R13 and IRO-008-2 R4.

TOP-001-3 R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

IRO-008-2 R4: Each Reliability Coordinator shall ensure that a Real□time Assessment is performed at least once every 30 minutes.

The process an entity develops to avoid a violation of these requirements will necessitate prompt notification any time the entity's ability to perform the Real Time Assessment is degraded. Additional requirements would therefore be either redundant or unnecessarily prescriptive.

BPA notes that a measurement of the **quality** of monitoring or analysis tools is likely to be closely dependent on the tools and processes implemented by the individual entity. However, BPA agrees with the SAR DT that ongoing assessment of the tools and processes implemented by an entity to perform Real-time Assessment is both necessary and a gap in the existing standards. It is important to avoid the pitfall of implicitly requiring a specific implementation for Real Time Assessment. Any new standards developed by Project 2009-02 must also allow the industry to continue developing and improving on the best practices described by the NERC Real Time Best Practice Task Force in 2008.

Therefore, BPA suggests that Project 2009-02 should only focus on developing requirements for entities to establish, based on their own local implementation, 1) procedures for evaluating the quality of their Real Time Assessment and the information needed to perform it, and 2) the processes for maintaining the quality of the required information to the performance thresholds the entity determines are necessary for performing the Real Time Assessment.

Document Name:

Likes: 0

Dislikes: 0

Provide any additional comments for the Standard Drafting Team (SDT) to consider, if desired.

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:

The NSRF wishes to point out that our industry has recently approved TOP-001-3 and it is currently pending approval from FERC. Specifically, R8, R10, R10.1, R10.2, R11, R12, R13, and R19 addresses several blackout recommendations concerning knowing how your system is performing and how to communicate mitigating actions to others. Please take this into consideration when developing this Standard.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NA - Not Applicable

Group Information

Group Name: Standards Review Committee (SRC)

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Matthew Goldberg	ISO-NE	NPCC	2
Christina Bigelow	ERCOT	TRE	2
Terry Bilke	MISO	MRO	2
Al Dicaprio	PJM	RFC	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Kathleen Goodman

Segment

2

Entity

ISO New England, Inc.

Region(s)

NA - Not Applicable

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy has the following additional comments: 1. When writing standards for issues that are technology driven, extreme care must be used to avoid arbitrarly increasing costs without commensurare increase in benefit to reliability. 2. Standards should be technology neutral to the extent possible. 3. Need a bright-line voltage level guidance for which these new requirements apply. Different entities have their own definition of what consitutes Transmission levels. There presently exists a range from 100 kV to 44 kV in our region. 4. Need a bright-line guidance regarding extent of external monitoring that needs to be performed. A specific number, for example 10% impact, on internal lines and transformers would be extremely helpful. Currently entities in our region monitor anywhere from 5% to 10% impact, if possible, or up to three buses away.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Xcel Energy has questions about any new standards or proposed revisions to existing standards that would result from this project. How stringent are the requirements going to be? Will fully redundant systems be required? Can a TOP rely on the RC or other entity as a temporary backup? What about if the RC goes down?

Additionally, we have concerns about the level of detail that would be required. We believe that a requirment to analyze contingencies on neighboring systems could cause undue burden on smaller systems with larger neighbors.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2009-02

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1

Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**

Northeast Power Coordinating Council NPCC

Selected Answer:

Answer Comment:

Any revisions made must not address the specifics of what the situational awareness capabilities are, but must focus on the adequacy of the monitoring and analysis.

This proposed project should be considered for a guideline document as opposed to a standard. As written, the SAR appears to intend to write a "how" not "what" standard (i.e. it does appear to be a results-based standard). We believe that the existing Standards (i.e. IRO, TOP and BAL) sufficiently define what needs to be monitored by each entity without defining the tools (i.e. without defining the "how"), which is appropriate.

As an alternative, this could be considered a process to be used for certifying new entities for assurance that they have the ability to monitor appropriately in accordance with the Standard's Requirements.

To avoid these issues in the future and to support communicating to FERC that a standard is not needed but another tool is more suitable, we suggest the future SARs be voted on by industry as to whether to proceed as a Standards project or use another means to achieve the ends.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

2009-02 Real-time monitoring and analysis capabilities-S15 (Page 18 & 19), S18 (Page 21 and 22) and S33 (Page 26) all list EOP-011-1. EOP-011-1 is not effective due to not being approved by FERC. Although EOP-011-1 was written to consolidate EOP-001-2.1b, EOP-002-3.1 and EOP-003-2, we question if this project should be listing EOP-011-1 rather than the other 3 standards which are effective and approved.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - Real-time Project

Group Member Name	Entity	Region	Segments
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

There are two minor issues in the SAR Justification. On page 11, the last paragraph refers to Table 1. Yet, there is no Table 1. We assume Table 2 is supposed to be Table 1.

On page 15 regarding recommendation S3, "Addresses" should be "Addressed."

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1,3 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
John Allen	City Utilities of Springfield	SPP	1,4
Jason Smith	Southwest Power Pool Inc	SPP	2
Kevin Giles	Westar Energy,Inc.	SPP	1,3,5,6
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Jess Gray	Omaha Public Power District	MRO	3
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Sing Tay	Oklahoma Gas and Elecric, Inc	SPP	1,3,5,6
Scott Williams	City Utilities of Springfield	SPP	1,4

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE agrees with the RTBPTF report which states "Develop a new weather data requirement related to situational awareness and real-time operational capabilities." The drafting team's response, "EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard", is concerning because registered entities might not monitor weather as they should. Weather is extremely pertinent to situational awareness and real-time operational capabilities. Weather has a significant impact and, too often, exacerbates reliability issues. If it is a common utility practice than successful compliance should not be an issue. Is the SDT considering a Guideline like what was done for the common utility practice of preparing a generator for winter operation?

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

N/A

Document Name:

Likes: 0

Dislikes: 0

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2015-08 Emergency Operations

Comment Period Start Date: 07/21/2015

Comment Period End Date: 08/19/2015

There were 20 sets of responses, including comments from approximately 87 different people from approximately 66 different companies representing 7 of the 10 Industry Segments as shown on the following pages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-2560.

Questions

1. The scope of this project includes:
    - Implement the recommendations of the periodic review team related to the following standards:
        - EOP-004-2
        - EOP-005-2
        - EOP-006-2
        - EOP-00801
    - Improve quality, relevance and clarity of the standards
    - Bring standards into Results-Based format
    - Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel

    Do you agree with this scope? If not, please explain.

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

3. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. The scope of this project includes:

· *Implement the recommendations of the periodic review team related to the following standards:*

o *EOP-004-2*
o *EOP-005-2*
o *EOP-006-2*
o *EOP-008-1*

· *Improve quality, relevance and clarity of the standards*
· *Bring standards into Results-Based format*
· *Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel*

Do you agree with this scope? If not, please explain.

Summary Responses:

Many commenters made comments and recommendations for revisions to EOP-004, Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

To clarify from comments received, the EOP PRT *did not* recommend retirement of Requirement R10 in EOP-005 or Requirement R9 in EOP-006. The EOP PRT's final recommendation was that these requirements be evaluated for either *inclusion* into the PER family of standards; or, in the alternative, be *retained* in EOP-005 and EOP-006.

A comment was received regarding the approach for commenting and balloting Project 2015-08, Emergency Operations. The EOP SDT agrees with the approach utilized by the Project 2015-04 team. The EOP SDT will add commenting/balloting approach to its agenda for with the September 2015 kick-off meeting, or at its November 2015 in-person meeting. The EOP SDT will be required to have each standard's commenting and balloting conducted separately; however, since the revisions and retirements of requirements are being developed concurrently, the standards will likely post for commenting and balloting during the same time periods. The EOP SDT would not be allowed to ballot requirements and/or attachments separately from the standard they are contained within. Each standard would need to pass or fail ballot in its entirety. The EOP SDT will consider whether an informal comment period would be beneficial for each standard; in particular EOP-004 (due to attachments) during the development process, or whether focused outreach to gather industry inputs during development is more efficient and effective.

In response to a comment received, the EOP SDT will implement the recommendation of the EOP PRT by *reviewing* the VSL in Requirement R1 *to determine* if it should be revised for consistency with the VSL level in Requirement R2. The EOP SDT will consider all comments received on this revision prior to determining the appropriate action to take on the revision.

To clarify the EOP PRT's intent for the review for revision of Requirement R5 was to consider the current language of "implementation date" and consider if the use of the term "effective date," or "approval date" would provide additional clarity, or if the current language "implementation date" is clear as written.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name:	Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6

Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

We generally agree with the proposed scope, but would reiterate the following concerns/suggestions which we submitted when we commented on the initial posting of the PRT's recommendations. We propose that these concerns/suggestions be duly considered during standard drafting:

a. EOP-004

(IESO comment) We agree with the initial recommendation which outlines three clarifying revisions to Attachment 1 of EOP-004-2, but believe that this recommendation falls way short of providing the needed clarity to the obligations of the Responsible Entities listed in Attachment 1. We further believe that certain items listed in Attachment 1 serve to support post-mortem analysis but do not contribute to operating reliability, and may be redundant with similar requirements already stipulated in the Event Analysis Process document. We therefore offer the following comments:

· The lack of clarity can result in registered entities being found potentially noncompliant with certain requirements. As an example, on P.10 of EOP-004-2, when there is a loss of firm load ≥; 300 MW for entities with previous year’s demand ≥; 3,000 or ≥; 200 MW for all other entities, the BA, TOP or DP is held responsible for reporting. It is unclear on the size of MW in relation to which particular entity’s previous year’s demand size, and whether or not all three entities are responsible for reporting, or just one of them needs to report, and if so, which one of the three? Also, if it is meant to be one of the three, it is not clear whether or not the location or area within which the load loss occurs would dictate which one of the three entities has that obligation.

When the loss of load occurs in a distribution system, is it the DP’s obligation to report? Likewise, is the TOP obligated to report when the loss involves those loads that are tapped off the transmission network? Depending on the answer to the above, what is the role of the BA? Finally, if all three are obligated to report, doesn’t the requirement make it cumbersome and redundant when all three entities files reports to the recipient entities/authorities?

We believe that Attachment 1 needs to be revised to clarify the 3000 MW relationship with a specific entity’s previous year’s demand, and to hold a single entity responsible for reporting this type of events. The latter recommendation also applies to other events in Attachment 1 where there are multiple entities listed as having the obligation to take actions.

· We believe that the requirement to report loss of load is not needed for reliability, unlike their interruption to BES facility counterparts. Loss of load is usually caused by loss of facilities, or by frequency or voltage excursions resulting from events that are already listed in Attachment 1 (e.g., voltage deviation, generation loss, etc.). We further believe that while this information is needed for post-mortem event analysis, this information reporting requirement is already stipulated in the Event Analysis Process document, and mandated by local regulatory authorities. Reporting such events to the ERO, the RE and other entities is redundant and does not help to improve operating reliability. Further, since loss of load by itself does not have any impact on the Bulk Electric System reliability, reporting such events is inconsistent with the principle "….to report disturbances and events that threaten the reliability of the Bulk Electric System" as indicated in the Guideline and Technical Basis of the standard. We therefore suggest that this requirement be removed from Attachment 1 as it is not needed for operating reliability and is redundant with the requirement for event analysis stipulated elsewhere or mandated by local regulatory authorities.

· If for whatever reasons the loss of load reporting requirement is retained in Attachment 1, we request the SDT to provide the technical justification for the threshold values of ≥; 300 MW for entities with previous year's demand ≥; 3,000 or ≥; 200 MW for all other entities. We believe these thresholds are too low to warrant any special attention and reporting burden by the Responsible Entities. For example, an area load of several hundred MW that is normally supplied by two transmission lines may be lost due to one of the lines being out of serviced for maintenance while the other suffering a contingency loss. To avoid having to report such load loss resulting from routine operating practices and recognized contingencies (with respect to design and operating criteria), we believe the reporting threshold should be raised to a level of at least 1,000 MW. We further suggest the SDT seek input from the NERC technical committees on the threshold values if the SDT should decide to keep this requirement, which we believe is not needed for operating reliability. (End of IESO comment)

In the response to comment, the PRT indicates that:

[The EOP PRT will recommend in the SAR for the future drafting team to review recommendations based on the comments received for Attachment 1, but will not suggest specific rewrites. The EOP PRT believes all recommendations have merit and need a thorough review by the future SDT when formed for this standard.]

Also, in the redline recommendations, the PRT proposes that:

["…Attachment 1 - The EOP PRT recommends the future Standard Drafting Team (SDT) conduct a thorough review of Attachment 1 and consider the following revisions to Attachment 1 for clarity, such as…"; and "…differing regional data submittal requirements when reviewing EOP-004-2 for revisions."]

The SAR does not provide any details or specificities on which parts of Attachment 1 will be revised. It is unclear whether or not our specific comments/suggestions will be addressed during the standard drafting phase. We therefore urge the SDT to carefully consider the above comments/suggestions, as proposed in the PRT's response.

b. EOP-005

Again, we'd like to reiterate our previous comments below since the SAR does not provide any details or specificities on the treatment to the concerned requirement (R10), in the revised EOP-005 standard, or any other standard that this requirement will be mapped into:

(IESO comment) We do not agree with the proposal to retire Requirement R10 as we do not believe this requirement is duplicative of any requirements in PER-005-2.

We assess that the Independent Expert Panel's recommendation to retire R10 was based on its assessment that this requirement was duplicative of R3 of PER-005-1, which stipulates that:

R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.

This recommendation appeared to be appropriate at that time. However, in PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was in part based on the existence of Requirement R10 in EOP-005-2 (and R9 in EOP-006-2).

If Requirement R10 in EOP-005 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any standards. We therefore suggest that this requirement be retained. (End of IESO comment)

Note that the PRT's response (below) essentially agree with our concern, but the SAR does not provide any clear indication as to the proposed treatment to Requirement R10.

[The EOP PRT does not find that there is adequate justification providing annual system restoration training for System Operators in another standard. Therefore, the EOP PRT recommends that the future SDT evaluate moving R10 into the PER family of standards; and if unable, Requirement R10 will be maintained in EOP-005.]

c. EOP-006

Similar to EOP-005, we had a concern with the proposed retirement of Requirement R9. Therefore, we are reiterating our comments on EOP-006, below for the SDT's consideration:

(IESO comment) We agree with the proposed retirement of Parts R1.2, R1.3 and R1.4, but do not agree with retiring Requirement R9 (which mirrors R10 in EOP-005-2) as we do not believe this requirement is duplicative of any requirements in PER-005-2.

Similar to our comments on the proposed retirement of R10 in EOP-005-2, we assess that the Independent Expert Panel's recommendation to retire R9 in EOP-006-2 was based on its assessment that this requirement was duplicative of R3 in PER-005-1, which stipulates that:

R3. At least every 12 months each Reliability Coordinator, Balancing

Authority and Transmission Operator shall provide each of its System Operators with

	at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. The recommendation to retire R9 of EOP-006-2 appeared to be appropriate at that time. However, in PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training to RC operating personnel no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was in part based on the existence of Requirement R10 in EOP-005-1, and R9 in EOP-006-2. If Requirement R9 in EOP-006-2 is removed, then there will not be any requirement to provide system restoration training to operating personnel. We therefore suggest that this requirement be retained. The PRT's response is essentially the same as its response to our comment on EOP-005; hence it's not repeated here.
Response:	Thank you for your comments. Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards. EOP-005/EOP-006: The EOP PRT did not recommend retirement of Requirement R10 in EOP-005 or Requirement R9 in EOP-006. The EOP PRT's final recommendation was that these requirements be evaluated for either inclusion into the PER family of standards; or, in the alternative, be retained in EOP-005 and EOP-006.

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT agrees with the scope, but reiterates its comments and the SRC's comments on the results of the periodic review as well as the SRC's comments on the SAR.

Response: Thank you for your comment. Please see responses to SRC's comments below.

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: Yes

Answer Comment:

The SRC generally agrees with the proposed scope, but, as it was unclear through the PRT’s responses to comments whether or how such comments would be addressed by the SDT, the SRC would reiterate the following concerns/suggestions that were submitted as comments by the SRC on the initial posting of the PRT’s recommendations. The SRC requests that these concerns/suggestions be duly considered during standard drafting:

a. EOP-004

The SRC reiterates that the requirement to report loss of load is not needed for reliability, unlike their interruption to BES facility counterparts. Since loss of load by itself does not have any impact on the Bulk Electric System reliability, reporting such events is inconsistent with the principle “….to report disturbances and events that threaten the reliability of the Bulk Electric System” as indicated in the Guideline and Technical Basis of the standard. The SRC, therefore, suggests that this requirement be removed from Attachment 1 as it is not needed for operating reliability and is redundant with the requirement for event analysis stipulated through other regulatory authorities. If for whatever reasons the loss of load reporting requirement is retained in Attachment 1, the SRC requests that the SDT seek input from the NERC technical committees to provide the technical justification for the threshold values of

≥; 300 MW for entities with previous year's demand ≥; 3,000 or ≥; 200 MW for all other entities.

b. EOP-005

The SRC does not agree with the proposal to retire Requirement R10 as the Independent Expert Panel's recommendation to retire R10 was based on its assessment that this requirement was duplicative of R3 of PER-005-1, which stipulates that:

R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.

This recommendation appeared to be appropriate at that time. However, in PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. If Requirement R10 in EOP-005 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any standards. We therefore suggest that this requirement be retained.

c. EOP-006

Similar to EOP-005, the SRC had a concern with the proposed retirement of Requirement R9. Our comments on EOP-006 are, therefore, reiterated for the SDT's consideration.

The SRC does not agree with the proposal to retire Requirement R9 as the Independent Expert Panel's recommendation to retire R9 was based on its assessment that this requirement was duplicative of R3 of PER-005-1, which stipulates that:

	R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. This recommendation appeared to be appropriate at that time. However, in PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. If Requirement R9 in EOP-005 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any standards. We therefore suggest that this requirement be retained.
Response:	Thank you for your comments. Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards/attachments. EOP-005 and EOP-006: The EOP PRT did not recommend retirement of Requirement R10 in EOP-005 or Requirement R9 in EOP-006. The EOP PRT's final recommendation was that these requirements be evaluated for either inclusion into the PER family of standards; or, in the alternative, be retained in EOP-005 and EOP-006.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer:	Yes

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: Yes

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment: Texas RE agrees that clarifications included in the periodic review should be a starting point for improvement of the Reliability Standrads listed. Texas RE encourages the SDT selected to review comments in terms of ensuring reliability and clarifying references and requirements.

Response: Thank you for your comments. The EOP SDT will review comments/recommendations made to the EOP PRT during comment period, as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Ellen Watkin	Sunflower Electric Power Corporation	SPP	1

Selected Answer: Yes

Answer Comment: Our review team agrees with the scope of this project however, we would suggest to the drafting team to make sure they have implemented a strong differentiation process on what needs to be retired or proposed/recommended for all the standards involved in this project. In the past, there has been confusion in the voting process to where one project has an affliation with other projects in the Stanard Development Process and a negative vote has delayed the entire project due to small details not being communicated effectively. Additionally, we would suggest using the approach

	taken by the Alignment of Terms Drafting Team (Project 2015-04). They submitted twenty-six terms to be voted on however, the industry had to vote on each individual term. So if the industry voted no for one term or terms, it would call for an re-evaluation for those particular term(s) and not cause a delay to the entire project (unless the changes were significant enough).
Response:	Thank you for your comments. The EOP SDT agrees with the approach utilized by the Project 2015-04 team. The EOP SDT will add commenting/balloting approach to its agenda for with the September 2015 kick-off meeting, or at its November 2015 in-person meeting. The EOP SDT will be required to have each standard's commenting and balloting conducted separately; however, since the revisions and retirements of requirements are being developed concurrently, the standards will likely post for commenting and balloting during the same time periods. The EOP SDT would not be allowed to ballot requirements and/or attachments separately from the standard they are contained within. Each standard would need to pass or fail ballot in its entirety. The EOP SDT will consider whether an informal comment period would be beneficial for each standard; in particular EOP-004 (due to attachments) during the development process, or whether focused outreach to gather industry inputs during development is more efficient and effective.

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments

Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8

RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: Yes

Answer Comment:

We have the following concerns for EOP-004:

There is a need to clarify the obligations of the Responsible Entities listed in Attachment 1.

On page 10 of EOP-004-2, when there is a loss of firm load ≥300 MW for entities with a previous year’s demand ≥3,000 MW, or ≥200 MW for all other entities, the BA, TOP or DP is held responsible for reporting. It is unclear as to the MW in relation to which particular entity’s previous year’s demand, and whether or not all three entities are responsible for reporting, or just one of them needs to report, and if so, which one of the three? Also, if it is meant to be one of the three, it is not clear whether or not the location or area within which the load loss occurs would dictate which one of the three entities has that obligation.

When the loss of load occurs in a distribution system, is it the DP’s obligation to report? Likewise, is the TOP obligated to report when the loss involves those loads that are tapped off the transmission network? Depending on the answer to the above, what is the role of the BA? If all three are obligated to report, the requirement makes it cumbersome and redundant to have all three entities file reports to the recipient entities/authorities.

Response: Thank you for your comments. The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Selected Answer: Yes

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:	EOP-004 – agree with retiring R3 (annual validation of contacts listed in event reporting operating plan) and with suggested changes throughout the standard (providing clarity for who is responsible for reporting) EOP-005 – Agree with the EOP PRT to *not* retire R12 as it is *not* duplicative with PER-005-1 R3. Agree with including R7 and R8 into R1 Agree with removing R3.1 which was retired by FERC on 1/21/14 Agree that R10 could possibly be moved to the PER standards if R12 remains in EOP-005 EOP-006 – neutral on retiring R1.2, R1.3, and R1.4 due to redundancy with R1.5 Agree with not retiring R10 as it is not captured in PER-005 Agree with including R7 and R8 into R1 Neutral on recommendation to add time frame for R4 (review of neighboring RC restoration plans) Agree that R9 could possibly be moved to the PER standards if R10 remains in EOP-006 Agree more precise expectations should be included in R10.1 (GOPs must participate in RC training exercise…), would prefer that only black start GOPs must attend the RC restoration training drills EOP-008 – Agree with adding clarity to timing or removing the statement in R1.1

Response:	The EOP SDT appreciates your support of the EOP PRT's final recommendations.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	No
Answer Comment:	In regard to the Project 2015-02 PRT's recommendations, BPA disagrees with: 1 - EOP-004: R1 VSL change increase 2 - EOP-004 Attachment 1: eliminating GOP from reporting, BPA believes it should be by initiating BA or initiating GOP. If a major plant has an internal problem and trips the GOP should do the investigation (not the BA). 3 - EOP-005: Page 5 "#2 Clarity" (version 2 R5 already uses "implementation date"), with R6 change. 4 - EOP-005: elimination of "Blackstart Resources"from R7 & R8.
Response:	Thank you for your comments. EOP-004, Requirement R1: The EOP SDT will implement the recommendation of the EOP PRT by reviewing the VSL in Requirement R1 to determine if it should be revised for consistency with the VSL level in Requirement R2. The EOP SDT will consider all comments received on this revision prior to determining the appropriate action to take on the revision. EOP-004, Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards/attachments.

EOP-005: The EOP PRT's intent for the review for revision of Requirement R5 was to consider the current language of "implementation date" and consider if the use of the term "effective date," or "approval date" would provide additional clarity, or if the current language "implementation date" is clear as written.
EOP-005: Requirements R7 and R8 (Blackstart Resources). The EOP SDT is unclear as to your comment regarding these requirements. The EOP PRT did not make a recommendation for elimination of Blackstart Resources from Requirements R7 and R8; rather the recommendation was to review these two requirements for possible merging into Requirement R1.

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

Summary Responses:
Many commenters made comments and recommendations for revisions to EOP-004, Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT agrees with the functional assignments, but reiterates its comments submitted in response to the periodoc review recommendations that redundancy across functions is inefficient and onerous and should be re-evaluated.

Response: Thank you for your comments. The EOP SDT will review comments/recommendations made to the EOP PRT during comment period (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: Yes

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: Yes

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: Yes

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Ellen Watkin	Sunflower Electric Power Corporation	SPP	1

Selected Answer: Yes

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments

Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8

RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	**Entity**	**Region**	**Segments**
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Selected Answer: Yes

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

3. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance:

Summary Responses:
All commenters responded "No." No regional variances are identified by comments.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Selected Answer: No

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: No

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Thomas Foltz - AEP - 5 -

Selected Answer: No

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: No

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: No

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: No

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: No

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
James "Jim" Nail	City of Independence, Missouri	SPP	3,5

Ellen Watkin	Sunflower Electric Power Corporation	SPP	1

Selected Answer: No

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: No

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9

Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: No

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	**Entity**	**Region**	**Segments**
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Selected Answer: No

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice:

Summary Responses:
No business practice was identified as being needed or modified as a result of Project 2015-08 Emergency Operations.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Selected Answer: No

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6

Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: No

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: No

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: No

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: No

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Without knowing the extent of the changes that will incur from this project, we are unable to provide specific examples of business practices that will be needed, or will need modification as a result of this project. However, it can be reasonably inferred that some business practices such as notification protocols, as well as**

operational procedures are going to need some modification depending on the extent of the revisions proposed.

Response: Thank you for your comment. For clarification, the specific question related to NAESB business practices; and not such things as operational protocols/procedures.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Ellen Watkin	Sunflower Electric Power Corporation	SPP	1

Selected Answer: No

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: No

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5

Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: No

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	**Entity**	**Region**	**Segments**
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Selected Answer: No

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

Summary Responses:

In response to the comment received to coordinate Event Reporting obligations across agencies, the EOP PRT intends to address potential efficiencies to be gained between EOP-004, ERO Event Analysis Process, and the U.S. Department of Energy's (DOE) OE-417 report and recommends that the EOP SDT review for possible better alignment. Following extensive discussion regarding the relationship between EOP-004-2 reporting and the DOE OE-417 report, the EOP SDT has entered into an ongoing collaborative effort with the DOE to better align reporting requirements for U.S. entities.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Selected Answer: No

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: No

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment: **The Ontario Energy Board (Ontario energy regulator) has in place electricity reporting requirements for Ontario distribution providers. Loss of Supply is an electricity reporting requirement that is filed by Ontario distribution providers to the Ontario Energy Board (and not the Ontario IESO which is the RC, BA and TOP for the Ontario integrated grid).**

Response: Thank you for your comment.

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: **The Public Utility Commission of Texas has both emergency and outage reporting forms and requirements.**

Response: Thank you for your comment.

Thomas Foltz - AEP - 5 -

Selected Answer: No

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: Yes

Answer Comment: **The Ontario Energy Board (Ontario energy regulator) has in place electricity reporting requirements for Ontario distribution providers. Loss of Supply is an electricity reporting requirement that is filed by Ontario distribution providers to the Ontario Energy Board.**

The Public Utility Commission of Texas has both emergency and outage reporting forms and requirements.

Response: Thank you for your comments.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: No

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: No

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: No

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
James "Jim" Nail	City of Independence, Missouri	SPP	3,5
Ellen Watkin	Sunflower Electric Power Corporation	SPP	1

Selected Answer: No

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: No

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3

Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5

Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: Yes

Answer Comment: An effort to coordinate Event Reporting obligations across agencies should be undertaken. Currently, entities are required to report to NERC and to the DOE, potentially in different time frames and with a different level of detail. If these could be made more consistent moving forward, it would reduce the administrative burdens associated with Event Reporting. This should be added to the scope of the SAR for consideration.

The Ontario Energy Board (Ontario energy regulator) has in place electricity reporting requirements for Ontario distribution providers. Loss of Supply is an electricity reporting requirement that is filed by Ontario distribution providers to the Ontario Energy Board (and not the Ontario IESO which is the RC, BA and TOP for the Ontario integrated grid).

Response: Thank you for your comments.

Event Reporting obligations: In response to the comment received to coordinate Event Reporting obligations across agencies, the EOP PRT intends to address potential efficiencies to be gained between EOP-004, ERO Event Analysis Process, and the U.S. Department of Energy's (DOE) OE-417 report and recommends that the EOP SDT review for possible better alignment. Following extensive discussion regarding the relationship between EOP-004-2 reporting and the DOE OE-417 report, the EOP SDT has entered into an ongoing collaborative effort with the DOE to better align reporting requirements for U.S. entities.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Selected Answer: No

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.

Summary Responses:
Many commenters made comments and recommendations for revisions to EOP-004, Attachment 1: The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

The EOP SDT will continue to review the rationale box for dynamic simulations and any other comments that industry provides in the future.

In response to the comment received to coordinate Event Reporting obligations across agencies, the EOP PRT intends to address potential efficiencies to be gained between EOP-004, ERO Event Analysis Process, and the U.S. Department of Energy's (DOE) OE-417 report and recommends that the EOP SDT review for possible better alignment. Following extensive discussion regarding the relationship between EOP-004-2 reporting and the DOE OE-417 report, the EOP SDT has entered into an ongoing collaborative effort with the DOE to better align reporting requirements for U.S. entities.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1

Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

The NSRF has reviewed the Project page containing the proposed redlined to last approved Standards and believes this is a good starting point for the SDT to complete this project.

Response: Thank you for your comment.

Thomas Foltz - AEP - 5 -

Answer Comment:

The purpose/goal for the SAR associated with Project 2015-08 (Emergency Operations) states in part "…implement the recommendations of the Project 2015-02 EOP PRT to revise EOP-004-2, EOP-005-2, EOP-006-2, and EOP-008-1". Page 4 of the Project 2015-02 EOP PRT report on PRC-005-2 has a list of items for consideration. Our comments below are in response to some of the recommendations made in this report.

Item b states that "the EOP PRT recommends the future SDT consider findings from any future-published reports as they relate to EOP-005-2." We also suggest reaching out to the North American Transmission Forum for input as appropriate.

Item h states that "the EOP PRT recommends the future SDT review Requirement R6 for clarification of the terms "steady state" and "dynamic simulations, including considering the addition of a Rationale Box." We believe there is need for practicality regarding the addition of a Rational Box to clarify dynamic simulations . System restoration is not defined as restoring power to each and every load. Rather, EOP-005-2 R1 uses practical language which states that the completion of system restoration is "…a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage…".

Response:

Thank you for your comments.
The EOP SDT will consider gathering inputs from the North American Transmission Forum (NATF), where appropriate, during development of revisions and retirements of these standards.

The EOP SDT will continue to review the rationale box for dynamic simulations and any other comments that industry provides in the future.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment: **While Duke Energy supports the project, we have concerns for the potential of "scope creep" due to the broad implications of the EOP-004 attachment on the requirements of reporting. There could be potential for the Drafting Team to become bogged down in trying to coordinate between Event Analysis reporting and OE-417 reporting. The Drafting Team should be given clear direction on what needs to be modified as part of the project.**

Response: Thank you for your comment.

Event Reporting obligations: In response to the comment received to coordinate Event Reporting obligations across agencies, the EOP PRT intends to address potential efficiencies to be gained between EOP-004, ERO Event Analysis Process, and the U.S. Department of Energy's (DOE) OE-417 report and recommends that the EOP SDT review for possible better alignment. Following extensive discussion regarding the relationship between EOP-004-2 reporting and the DOE OE-417 report, the EOP SDT has entered into an ongoing collaborative effort with the DOE to better align reporting requirements for U.S. entities.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2015-08

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5

Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Answer Comment:

In the Detailed Description section of the SAR, the sentence “There are no market interface impacts resulting from the standard action on the implementation of the Project 2015-02, EOP PRT’s recommendations.” should be revised. There are no direct impacts to the market interface from “the standard action on the implementation of the Project 2015-02, EOP PRT’s recommendations.”

“The EOP Periodic Review Team (EOP PRT) is recommending that the future Standards Drafting Team (SDT) revise Requirement 1 part R1.1 to provide clarity, as the team determined it would be difficult to establish a timing requirement to restore primary control center functionality given the range of events that could render the primary control center inoperable”. Considering a system reliability need for generation, there are entities that have market interface equipment in their primary control center only. If the primary control center becomes inoperable it will have an effect on how fast an entity is able to get generation online in order for support. Please change the language to “direct impacts” instead.

It is recognized that continued operation of a market is not a reliability issue; in this situation, manual dispatch should continue to occur.

Suggest that any update to EOP-004-2 should include a re-synchronization of the EOP-004’s Attachment 1 (Reportable Events) with the list of Categories in the ERO’s

Event Analysis Process – Version 3 document. Any change to EOP-004 going forward should consider the latest version of the EAP.

Response: Thank you for your comments. The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments), as many received had merit and the EOP SDT intends to make a thorough review of these comments in consideration of developing the revisions to the standards.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - EOP Project

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Ginger Mercier	Prairie Power, Inc.	SERC	3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Answer Comment: We recommend that the drafting team consider whether there are opportunities to carve out lower risk entities from the applicability section in the standard. This would be consistent with the approaches of the Risk Based Registration initiative by right-sizing compliance responsibilities for low-risk entities.

Response:	Thank you for your comment. The EOP SDT will review comments/recommendations made to the EOP PRT during comment period of final recommendations (as well as these SAR comments).

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment:	N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Generator Operators

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan

5. **Effective Date:** See the Implementation Plan for EOP-005-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has at least once each 15 calendar months reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.

Therefore, the EOP SDT revisions now provide clarity. By revising this to read as "to reflect System modifications that would change the ability to implement its restoration plan," the intent was that the TOP update its restoration plan when major modifications need to be made that affect its ability to implement its restoration plan as describe in Requirement R1 Parts, not that the Transmission Operator has to make updates for minor revisions, such as element number changes or device changes that have no significance to the implementation of the plan.

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response for each step of the restoration. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

R8. Each Transmission Operator shall include within its operations training program, System restoration training at least once each 15 calendar months for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 would allow operating personnel to gain experience and coordination needed through all of the stages of restoration, including coordination needed in the transfer of control back to the Balancing Authority.

8.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition to Balancing Authority for Area Control Error and Automatic Generation Control.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in force since the last monitoring activity for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity, as well as one previous monitoring activity period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in force since its last monitoring activity for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in force since its last monitoring activity on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last monitoring activity records and all requested and submitted subsequent monitoring activity records.

1.3. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement it.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 121 calendar days 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at	The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator prior to a planned BES modification.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		least 20 calendar days prior to a planned change.	least 10 calendar days prior to a planned change.	
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator	N/A	The Transmission Operator and Generator Operator

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.		with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-~~2~~3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ~~assure~~ ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Generator Operators
     - **4.1.3.** Transmission Owners identified in the Transmission Operators restoration plan
     - **4.1.4.** Distribution Providers identified in the Transmission Operators restoration plan
5. **Effective Date:** See the Implementation Plan for EOP-005-3.~~Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~shutdown area to service.~~, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.~~ The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as ~~e-mails with~~dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator ~~annually~~ at least once each 15 calendar months on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~**3.1.** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retirement approved by FERC effective January 21, 2014.)~~

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, ~~e-mails with~~dated electronic receipts, or registered mail receipts, that it has ~~annually~~ at least once each 15 calendar months reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement ~~R3~~R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.

Therefore, the EOP SDT revisions now provide clarity. By revising this to read as "to reflect System modifications that would change the ability to implement its restoration plan," the intent was that the TOP update its restoration plan when major modifications need to be made that affect its ability to implement its restoration plan as describe in Requirement R1 Parts, not that the Transmission Operator has to make updates for minor revisions, such as element number changes or device changes that have no significance to the implementation of the plan.

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan ~~within 90 calendar days after identifying any unplanned permanent~~to reflect System modifications~~,~~ that would change the ability ~~or prior~~ to ~~implementing~~ implement ~~a planned BES modification, that would change the implementation of~~ its restoration plan, as follows:~~.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. ~~Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same~~ No more than 90 calendar ~~day period~~days after the Transmission Operator identifies any unplanned System modifications; and~~.~~

~~4.1.~~4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision ~~histories, e-mails with~~histories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its ~~implementation~~ effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, ~~available~~ in its primary and backup control rooms and available to its System Operators prior to its ~~implementation~~ effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response for each step of the restoration. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years~~ at a minimum~~. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. ~~Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each~~

~~affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration.~~ ~~*[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~**M7.**~~ ~~If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.~~

R8. ~~Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator.~~ ~~*[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~**M8.**~~M7. ~~If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.~~

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement ~~R9~~R7.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 would allow operating personnel to gain experience and coordination needed through all of the stages of restoration, including coordination needed in the transfer of control back to the Balancing Authority.

R8. Each Transmission Operator shall include within its operations training program, ~~annual~~ System restoration training at least once each 15 calendar months for its System Operators~~ to assure the proper execution of its restoration plan~~. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- **8.1.** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan
- **8.2.** Restoration priorities
- **8.3.** Building of cranking paths
- **8.4.** Synchronizing (re-energized sections of the System)
- **~~8.4.~~8.5.** Transition to Balancing Authority for Area Control Error and Automatic Generation Control

~~M9.~~M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement ~~R10~~R8.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M10.~~M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement ~~R11~~R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M11.~~**M10.** Each Transmission Operator shall have evidence~~, such as training records,~~ that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement ~~R12~~R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M12.~~**M11.** Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement ~~R13~~R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M13.~~**M12.** Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement ~~R14~~R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M14.~~**M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within ~~twenty-four~~24 hours of such changes in accordance with Requirement ~~R15~~R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement ~~R9~~R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

~~M15.~~M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement ~~R16~~R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator.

15.2. The procedures documented in Requirement ~~R14~~R12.

~~M16.~~M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement ~~R17~~R15.

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M17.~~M16. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement ~~R18~~R16.

C. Compliance

1. Compliance Monitoring Process

Compliance Enforcement Authority: ~~Regional Entity.~~
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

Compliance Monitoring Period and Reset Time Frame: ~~Not applicable~~
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to

provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in force since the last ~~compliance audit~~monitoring activity for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's ~~annually~~ reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- ~~Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.~~
- ~~Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.~~
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement ~~R9~~R7, Measure ~~M9~~M7.
- ~~Actual training~~ Training program materials or descriptions for three calendar years for Requirement ~~R10~~R8, Measure ~~M10~~M8.

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~compliance audit~~monitoring activity, as well as one previous ~~compliance audit~~monitoring activity period for Requirement ~~R12~~R10, Measure ~~M12~~M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution ~~provider~~ Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- ~~Actual training~~ Training program materials or descriptions and ~~actual~~ training records for three calendar years for Requirement ~~R11~~R9, Measure ~~M11~~M9.

If a Transmission Operator, applicable Transmission ~~owner~~Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in force since its last ~~compliance audit~~monitoring activity for Requirement ~~R13~~R11, Measure ~~M13~~M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in force since its last ~~compliance audit~~monitoring activity on procedures to start each Blackstart Resource and for energizing a bus for Requirement ~~R14~~R12, Measure ~~M14~~M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement ~~R15~~R13, Measure ~~M15~~M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement ~~R16~~R14, Measure ~~M16~~M14.

- ~~Actual training~~ Training program materials and ~~actual~~ training records for three calendar years for Requirement ~~R17~~R15, Measure ~~M17~~M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~compliance audit~~monitoring activity for Requirement ~~R18~~R16, Measure ~~M18~~M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last monitoring activity~~audit~~ records and all requested and submitted subsequent monitoring activity~~audit~~ records.

1.1. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the ~~sub-~~requirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the ~~sub-~~requirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three of the ~~sub-r~~requirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement it.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was up to 10 calendar days late in doing so.~~	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more than 10 and less than or~~	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more than 20 and less than or~~	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		~~equal to 20 calendar days late in doing so.~~	~~equal to 30 calendar days late in doing so.~~	description of any changes to their roles and specific tasks prior to the effective date.~~The Transmission Operator provided the information to all entities but was more than 30 calendar days late in doing so.~~
R3.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the mutually-agreed, pre-determined schedule.
R4.	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change. OR	The Transmission Operator ~~failed to~~ updated and ~~submit~~ submitted its restoration plan to the Reliability Coordinator ~~within more than 90~~ between 91 calendar days ~~but less than~~ and 120	The Transmission Operator ~~has failed to~~ updated and ~~submit~~ submitted its restoration plan to the Reliability Coordinator ~~within more than 120~~ between 121 calendar days ~~but less than~~ 150 calendar	The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within ~~more than~~ 150 calendar days of an unplanned change. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.	calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.	days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change.	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator prior to a planned BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its ~~implementation~~ effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the ~~sub-~~	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the ~~sub-~~	The Transmission Operator performed the verification but did not complete it within the ~~five calendar~~	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~requirements~~requirement parts.	~~requirements~~requirement parts.	~~year period~~required time frame.	OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the ~~sub-requirements~~requirement parts.
~~R7.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not implement its restoration plan following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES. Or, if the restoration plan cannot be executed as expected, the Transmission Operator did not utilize its restoration plan strategies to facilitate restoration.~~
~~R8.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service.~~
~~R9~~R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the ~~sub-requirements~~requirement parts of Requirement ~~R9~~R7.
~~R10~~R8.	The Transmission Operator's training does not address one of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address two of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address three or more of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator has not included System restoration training in its operations training program.
~~R11~~R9.	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement ~~R11~~ R9 within a two-~~-~~calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement ~~R11~~ R9 within a two-calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement ~~R11~~ R9 within a two-calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement ~~R11~~ R9 within a two-~~-~~calendar-~~-~~year period.
~~R12~~R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for ~~their~~ its participation from the Reliability Coordinator.
~~R13~~R11.	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
~~R14~~R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				procedures for each Blackstart Resource.
~~R15~~R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.
~~R16~~R14.	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in ~~R16.1~~Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 ~~days~~ to 90 calendar days after the request.	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days ~~of~~ after the request.			
~~R17~~R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement ~~R17~~ R15 within a two-~~-~~calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement ~~R17~~ R15 within a two-calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement ~~R17~~ R15 within a two-calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement ~~R17~~ R15 within a two-~~-~~calendar-~~-~~year period.
~~R18~~R16.	N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator’s restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with adjacent Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 15 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 15 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months, System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator

7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and R8 Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in force for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in force for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.

- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Processes Program

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information: None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 15 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the System restoration training at least once each 15 calendar months within its operations	The Reliability Coordinator did not include the System restoration training at least once each 15 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			training program, but did not address both of the requirement parts.	months within its operations training program.
R8.	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.	The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/15 – 08/19/15

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 - 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-~~2~~3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Proposed Effective Date:** ~~Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~ See the Implementation Plan for EOP-006-3.
6. Standard-Only Definition: None.

B. Requirements and Measures

R1. Each Reliability Coordinator shall ~~have~~ develop, maintain, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

~~**1.2.** Operating Processes for restoring the Interconnection.~~

~~**1.3.** Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~

~~**1.4.** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

~~1.5.~~1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with ~~other~~ adjacent Reliability Coordinators.

~~1.6.~~1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

~~1.7.~~1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

~~1.8.~~1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

~~1.9.~~1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan ~~in accordance with Requirement R1~~and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as ~~e-mails with~~electronic receipts, posting to a secure web-site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within ~~13~~ 15 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within ~~13~~ 15 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review ~~their~~ its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If ~~the~~ a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved ~~in~~ within 30 calendar days of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence~~,~~ such as a dated review signature sheet or ~~emails~~electronic receipt~~,~~ that it has reviewed, approved or disapproved, and notified its Transmission Operator~~'~~s within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the ~~implementation~~ effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as ~~e-mail~~electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the ~~implementation~~ effective date in accordance with Requirement R6.

~~**R7.** Each Reliability Coordinator shall work with its affected Generator Operators, and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~**M7.** Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.~~

~~**R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~M8.~~M7. ~~If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.~~

~~R9.~~R7. Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months,~~annual~~ System restoration training for its System Operators~~ to assure the proper execution of its restoration plan~~. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~9.1.~~7.1. The coordination role of the Reliability Coordinator

~~9.2.~~7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement ~~R9~~R7.

~~R10.~~R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~10.1.~~8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable ~~and that~~ Transmission Operator~~s~~ and Generator Operator~~s~~ to participate per Requirement R8 and R8 Part 8.1. ~~included in the Reliability Coordinator's restoration plan were invited in accordance with Requirement R10.~~

C. Compliance

1. Compliance Monitoring Process

Compliance Enforcement Authority: ~~Regional Entity~~
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.1. Compliance Monitoring Period and Reset Time Frame Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in force for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in force for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- ~~If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R7, Measure M7.~~

- ~~If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R8, Measure M8.~~
- Actual training program materials or descriptions for three calendar years for Requirements ~~R9~~R7, Measure ~~M9~~M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R10~~R8, Measure ~~M10~~M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.2. Compliance Monitoring and Enforcement Processes Program

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Additional Compliance Information: None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one ~~sub-~~ requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two ~~sub-~~ requirement~~s~~ parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the ~~sub-~~requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the ~~sub-~~ requirement~~s~~ parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within ~~13~~ 15 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 60 calendar days.~~	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 90 calendar days.~~	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 120 calendar days.~~	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 120 calendar days.~~
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the ~~implementation~~ effective date.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~implementation~~ effective date.	
~~R7.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ ~~OR~~ ~~When the restoration plan cannot be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate System restoration.~~
~~R8.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not coordinate or~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.~~ ~~OR~~ ~~If the resynchronization could not be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate resynchronization.~~
~~R9~~R7.	N/A	N/A	The Reliability Coordinator included the ~~annual~~ System restoration training at least once each 15 calendar months within its operations training program, but did not address both of the ~~sub-~~requirement~~s~~ parts.	The Reliability Coordinator did not include the ~~annual~~ System restoration training at least once each 15 calendar months within its operations training program.
~~R10~~R8.	The Reliability Coordinator only held one restoration	The Reliability Coordinator did not ~~invite~~ request each	N/A	The Reliability Coordinator did not hold a restoration

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	drill, exercise, or simulation during the calendar year.	applicable ~~a~~ Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.		drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-008-2 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

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

2. **Number:** EOP-008-2

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See the Implementation Plan for EOP-008-2.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Interpersonal Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any

Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current and previous calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center functionality respectively.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was reviewed and approved at least once every 15 calendar months. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but it did not document the results. OR, The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct a test of its Operating Plan for backup functionality at least once every 15 calendar months. OR, The responsible entity conducted a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-008-2 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-~~1~~2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** ~~The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.~~ See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. ~~-~~This Operating Plan for backup functionality shall include~~ the following, at a minimum~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality~~ for the time it takes to restore the primary control center functionality~~.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include~~, at a minimum~~:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. ~~Voice~~ Interpersonal ~~communications~~Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include ~~at a minimum~~:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in ~~force~~ effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in ~~force~~ effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less

- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. ~~-~~To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall ~~annually~~ review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~-~~to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator~~,~~ shall have evidence that its dated, current, and in ~~force~~ effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved ~~annually~~ at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct ~~and document results of an annual~~ a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall ~~that~~ demonstrate~~s~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its ~~annual~~ test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with

mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved ~~annually~~ at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current and previous calendar years ~~and one previous year~~, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center functionality respectively.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was ~~annually~~ reviewed and approved at least once every 15 calendar months. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but it did not document the results. OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months. OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standards

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirements

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standards

None

Applicable Entities

- Transmission Operators
- Generator Operators
- Transmission Owners identified in the Transmission Operators Restoration Plan
- Distribution Providers identified in the Transmission Operators Restoration Plan
- Reliability Coordinators
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing the outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources
Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

2015-08 Emergency Operations

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Opreations; EOP-005-3 – System Restoration from Blackstart Resources, EOP-006-3 – System Restoration Coordination, and EOP-008-2 – Loss of Control Center Functionality**. The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Standards Developer Manager, Sean Cavote (via email), or at (404) 446-9697..

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT) that resulted from the PRT's review of a subset of EOP Standards. The PRT comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous.

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 –Revise the standard; and
- EOP-008-1 – Revise the standard.

The four NERC Reliability Standards in the Periodic Review project concerned methodologies for restoring, reporting, and communicating Emergencies. Implementation of revisions and retirements recommended by the EOP PRT clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards, while making the standards more Results-based.

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “High” which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement it.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "implementation" with "effective" and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 121 calendar days 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change.	The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator prior to a planned BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "implementation" with "effective." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "their" with "its." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “High” which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	High
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	Moderate	High	Severe
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement part” and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

disapproval with reasons within 45 calendar days of receipt.	disapproval with reasons within 60 calendar days of receipt	notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “implementation date” with “effective date.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the System restoration training at least once each 15 calendar months within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the System restoration training at least once each 15 calendar months within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “annual” with “at least once each 15 calendar months” and by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.	The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is a requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The EOP SDT removed the language: "*…to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System*" in Requirement R1, as it is covered in Requirement R1, Part 1.8. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	The language, "…at least once each 15 calendar months…" was added to provide clarity. Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.		
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. This language creates two ambiguities. First, the phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes; however, no time frame is specified for updating the restoration plan for a planned BES modification. One could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Second, the distinction between “System modifications” for unplanned changes and “BES modifications” for planned changes is confusing. Some “system modifications” can include “BES modifications”. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan. For clarity, the EOP SDT revise the language in this Requirement to require a TOP to update its restoration plan to only reflect System modifications that affect its ability to implement its restoration plan as describe in Requirement R1 Parts. The intent is not to capture minor modifications that would have no impact on the implementation of a restoration, such as element number changes or device changes that have no significance to the implementation of the plan.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan	EOP-005-3, Requirement R4, Parts 4.1 and 4.2	The EOP SDT revisions harmonize the use of “System modification” and clarify the timing

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
to its Reliability Coordinator for approval within the same 90 calendar day period.	**4.1.** No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications. **4.2.** No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.	for unplanned and planned System modifications.
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1.** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2.** Restoration priorities.	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training at least once each 15 calendar months for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities.	The language, "…at least once each 15 calendar months…" was added to provide clarity and to align training with the timing for updates to the restoration plan. The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
10.3. Building of cranking paths. **10.4.** Synchronizing (re-energized sections of the System).	**8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition to Balancing Authority for Area Control Error and Automatic Generation Control.	
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop*

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		a guideline to aid entities in their compliance obligations.” The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the term “unique tasks.” The industry understands “unique tasks” to be those tasks that are defined by the TOP, TO, and the DP.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, maintain, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon*	Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" was added to distinguish between direct connection v. multiple neighbors (beyond direct connection). Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	*= Operations Planning, Real-time Operations]* **1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with adjacent Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the	"Implementation date" was revised to "effective date" for clarity.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop, maintain, and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop, maintain, and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months, System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Language for timeframe was added for clarity. "To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R5 **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-008-2, Requirement R5 **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor =*	The language, "…at least once each 15 calendar months…" was added to provide clarity.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Medium] [Time Horizon = Operations Planning]	
EOP-008-1, Requirement R7 **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-008-1, Requirement R7 **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	The language, "…at least once each 15 calendar months…" was added to provide clarity.

Standards Announcement
Reminder

Project 2015-08 Emergency Operations
EOP-005-3, EOP-006-3 and EOP-008-2

Initial Ballots and Non-binding Polls Open through August 15, 2016

Now Available

Initial ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, August 15, 2016** for the following standards:

- **EOP-005-3 System Restoration from Blackstart Resource**
- **EOP-006-3 System Restoration Coordination**
- **EOP-008-2 Loss of Control Center Functionality**

Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and non-binding polls by clicking here. If you experience any difficulties in using the electronic form, contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Updated
Standards Announcement

Project 2015-08 Emergency Operations
EOP-005-3, EOP-006-3, EOP-008-2

Formal Comment Period Open through August 15, 2016
Ballot Pools Forming through July 28, 2016

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, August 15, 2016** for the following standards:

- **EOP-005-3 System Restoration from Blackstart Resource**
- **EOP-006-3 System Restoration Coordination**
- **EOP-008-2 Loss of Control Center Functionality**

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, July 28, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 4 - 15, 2016.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Development, Sean Cavote (via email) or at (404) 446-9697.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 IN 1 ST
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 251
Total Ballot Pool: 312
Quorum: 80.45
Weighted Segment Value: 52.9

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	80	1	32	0.508	31	0.492	0	1	16
Segment: 2	9	0.8	3	0.3	5	0.5	0	0	1
Segment: 3	65	1	30	0.556	24	0.444	0	0	11
Segment: 4	18	1	10	0.714	4	0.286	0	0	4
Segment: 5	75	1	31	0.544	26	0.456	0	1	17
Segment: 6	51	1	23	0.523	21	0.477	0	0	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.5	2	0.2	3	0.3	0	0	3
Totals:	312	6.7	133	3.544	116	3.156	0	2	61

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Third-Party Comments
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Peak Reliability	Dave Thomas		Negative	Comments Submitted
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Negative	Comments Submitted
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Eversource Energy	Timothy Reyher		Negative	Comments Submitted
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NB Power Corporation	Laura McLeod		Negative	Third-Party Comments
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Negative	Comments Submitted
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Third-Party Comments
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Previous 1 Next

Showing 1 to 312 of 312 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 IN 1 ST
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 241
Total Ballot Pool: 297
Quorum: 81.14
Weighted Segment Value: 66.87

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	33	0.805	8	0.195	0	18	15
Segment: 2	9	0.7	3	0.3	4	0.4	0	1	1
Segment: 3	63	1	23	0.657	12	0.343	0	17	11
Segment: 4	17	0.7	5	0.5	2	0.2	0	6	4
Segment: 5	71	1	26	0.684	12	0.316	0	19	14
Segment: 6	49	1	20	0.667	10	0.333	0	13	6
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.5	4	0.4	1	0.1	0	0	3
Totals:	297	6.3	116	4.213	51	2.087	0	74	56

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Abstain	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Negative	Comments Submitted
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Abstain	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Abstain	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Abstain	N/A
5	Austin Energy	Jeanie Doty		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Abstain	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 297 of 297 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 IN 1 ST
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 244
Total Ballot Pool: 302
Quorum: 80.79
Weighted Segment Value: 84.13

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	78	1	53	0.869	8	0.131	0	1	16
Segment: 2	9	0.8	8	0.8	0	0	0	0	1
Segment: 3	64	1	44	0.83	9	0.17	0	0	11
Segment: 4	17	1	11	0.846	2	0.154	0	0	4
Segment: 5	70	1	47	0.855	8	0.145	0	1	14
Segment: 6	50	1	36	0.837	7	0.163	0	0	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.5	4	0.4	1	0.1	0	0	3
Totals:	302	6.7	205	5.637	37	1.063	0	2	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 302 of 302 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP IN 1 NB
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 227
Total Ballot Pool: 291
Quorum: 78.01
Weighted Segment Value: 55.74

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	25	0.556	20	0.444	12	16
Segment: 2	8	0.4	1	0.1	3	0.3	3	1
Segment: 3	65	1	27	0.6	18	0.4	7	13
Segment: 4	16	1	8	0.727	3	0.273	2	3
Segment: 5	69	1	21	0.538	18	0.462	12	18
Segment: 6	46	1	16	0.533	14	0.467	8	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	8	0.5	2	0.2	3	0.3	0	3
Totals:	291	6.3	102	3.455	81	2.845	44	64

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
	Exelon	Chris Scanlon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Negative	Comments Submitted
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Negative	Comments Submitted
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Previous 1 Next

Showing 1 to 291 of 291 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP IN 1 NB
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 220
Total Ballot Pool: 278
Quorum: 79.14
Weighted Segment Value: 69.63

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	27	0.794	7	0.206	21	14
Segment: 2	8	0.4	2	0.2	2	0.2	3	1
Segment: 3	63	1	22	0.688	10	0.313	19	12
Segment: 4	14	0.6	4	0.4	2	0.2	5	3
Segment: 5	65	1	20	0.667	10	0.333	20	15
Segment: 6	45	1	14	0.7	6	0.3	17	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	8	0.5	3	0.3	2	0.2	0	3
Totals:	278	5.9	94	3.948	41	1.952	85	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Abstain	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry Blike		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Abstain	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Abstain	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Abstain	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Abstain	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Previous 1 Next

Showing 1 to 278 of 278 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/55)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 NBP IN 1 NB
Voting Start Date: 8/4/2016 12:01:00 AM
Voting End Date: 8/15/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 223
Total Ballot Pool: 281
Quorum: 79.36
Weighted Segment Value: 85.33

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	40	0.889	5	0.111	11	15
Segment: 2	8	0.4	4	0.4	0	0	3	1
Segment: 3	64	1	38	0.844	7	0.156	7	12
Segment: 4	14	1	9	0.818	2	0.182	0	3
Segment: 5	65	1	35	0.875	5	0.125	10	15
Segment: 6	45	1	25	0.833	5	0.167	8	7
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	1
Segment: 9	2	0.1	0	0	1	0.1	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	8	0.5	4	0.4	1	0.1	0	3
Totals:	281	6.3	157	5.26	27	1.04	39	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Todd Komaromy	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		None	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Previous 1 Next

Showing 1 to 281 of 281 entries

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Updated
Standards Announcement

Project 2015-08 Emergency Operations
EOP-005-3, EOP-006-3, EOP-008-2

Formal Comment Period Open through August 15, 2016
Ballot Pools Forming through July 28, 2016

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, August 15, 2016** for the following standards:

- **EOP-005-3 System Restoration from Blackstart Resource**
- **EOP-006-3 System Restoration Coordination**
- **EOP-008-2 Loss of Control Center Functionality**

Commenting
Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Thursday, July 28, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps
Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 4 - 15, 2016.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Development, Sean Cavote (via email) or at (404) 446-9697.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2
Comment Period Start Date:	6/30/2016
Comment Period End Date:	8/15/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 NBP IN 1 NB

There were 64 sets of responses, including comments from approximately 58 different people from approximately 54 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Stan Rzad	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC

					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Paul Mehlhaff	Sunflower Electric Power Corporation	1	SPP RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bob Solomon	Hoosier Energy Rural Electric Cooperative,	1	RF

						Inc.		
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO

					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company Services, Inc	1	SERC
					John Ciza	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Robert Coughlin	Robert Coughlin		NPCC	SRC	Kathleen Goodman	ISO-NE	2	NPCC
					Ben Li	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Mark Holman	PJM	2	RF
					Liz Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ali Miremadi	CAISO	2	WECC
					Terry Bilke	MISO	2	RF
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion and NYISO	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York	4	NPCC

						Power Authority		
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen M. Goodman	ISO-NE	2	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schimtt	Nebraska Public Power	1,3,5	SPP RE

						District		
					Jerry McVey	Sunflower Electric	1	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Michelle Corley	Cleco	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
Lower Colorado River Authority	Teresa Cantwell	1		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Teresa Cantwell	LCRA	1	Texas RE

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP supports the overall direction and efforts of this project team, we have chosen to vote negative on EOP-005-2. Our negative vote is driven by our concerns regarding the obligation to reissue the entire restoration plan 30 days prior to the Transmission Operator's implementation of planned System modifications, even for minor revisions.

The proposed thirty-day window in R4 would be a difficult time frame to meet in many instances. Many jobs that are not directly created for the restoration plan, yet affect its restoration sequence, are often scheduled. However, these jobs are often rescheduled due to weather, system conditions or conflicting scheduled outages. Due to the possibility of multiple system improvements that may occur, which are either completed ahead of schedule or delayed during those 30 calendar days, we believe an accurate plan could not be maintained for the system operators. One option would be an addendum sheet that would contain the incremental changes and their implementation date, which could then be followed by a quarterly update to the restoration plan. This addendum sheet would be provided to all of the RTO and all the affected parties.

As the restoration plan is a voluminous document, AEP proposes to communicate with the RC only on the incremental changes (which could be only few sentences) rather than reissuing the entire, voluminous document.

AEP suggests modifying the proposed revision of R4 as suggested above, as well as completely eliminating the proposed R4.2.

Likes 0	
Dislikes 0	
Response	

Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	

The definition of a Balancing Authority is "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." During restoration, the local TO or TOP isolated island operations are not synchronized to the interconnection so they cannot support the interconnection frequency. Therefore, by definition, EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority should be removed. Balancing Authority functions will always reside with the designated Balancing Authority, even when operating as an isolated island. EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement R1 the revision should read that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3.

Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan.System modifications should be clearly defined. It should be limited to transmission and generation components. A definition of System modification should be added to the NERC Glossary.

EOP-005-3 Parts 1.9 and 8.5 which refer to transferring of Balancing Authority authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R3 and R8 is unnecessary, does not improve the standard, and is not consistent with numerous other standards that currently contain "Annual" requirements.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

Although generally supportive of the revisions made by the drafting team, the NSRF has concerns with the following requirements.

1.) **R1** - In consideration that developing and implementing a restoration plan represents two separate actions required by TOPs, we recommend the following change to R1 in order to clarify when the restoration plan is intended to be implemented.

"Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas…"

2. R8.5 needs to reworded. We understand the intent, which we agree with. Recommend from "Transition to Balancing Authority for Area Control Error and Automatic Generation Control" to "Transition back to Balancing Authority control for Area Control Error and Automatic Generation Control". This clearly states that a hand-off of responsibilities is warrented at the end of system restoration.

3.) We recommend retaining the current R1 language "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." We are concerned that deletion of the qualifying clause at the end of R1 will require an expansion of scope for all current Blackstart restoration plans.

Without the qualifying language, Transmission Operators are required to have a restoration plan for restoring the TOP's System, with Blackstart Resources required to restore the "shutdown area to service" without any qualification or limit to the "shutdown area" short of the TOP's entire BES "System."

In the worst case scenario when there is a total black out of the system the plan would have to be quite large. It would be difficult to cover all the variables and conditions that could likely be encountered. Maintenance of such a plan would be very difficult leading to compliance issues.

Possible alternative language: "The restoration plan shall allow for restoring the Transmission Operator's System following a disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to start generation for the restoration of the shutdown area to service."

4.) The replacement of “annual” with “at least once each 15 calendar months” in R3 & R8 introduces additional unnecessary administrative tracking requirements, restricting entities to submission or training, respectively, within a moving 4-month compliance window vs. the current flexibility of the entire calendar year. Demonstrating compliance would now require comparison with the previous completion date vs. showing annual accomplishment.

What is the justification for this complication? Preventing a possible interval of up to 23 months? What is the reliability risk of a 23-month interval vs. a 15-month interval? Such an occurrence would be self-correcting under the current annual requirement. If R3/8 were accomplished in Jan. 2018, and not again until Dec. 2019, the next occurrence would be required in Dec. 2020, no more than 12 months later, and earlier than the proposed new requirement of 15 months.

5. R4 – With Transmission Operators required to submit their updated restoration plan to the RC “no less than 30 calendar days prior to…planned System modifications”, we are concerned the new timeframe may require TOPs to maintain two versions of their restoration plan in the control room due to confusion in terms of which restoration plan is considered valid while awaiting energization of a planned System modification.

As an example, a System modification impacting the restoration plan is scheduled to occur on September 1st so a TOP submits an updated plan to their RC on July 29th. The RC reviews and approves the plan on August 19th. To comply with EOP-005 R2 and R5 which require the TOP to provide the plan to System Operators and identified entities “prior to the effective date”, the TOP distributes the newly approved plan on August 24th. Since the System modification is still over a week away from energization, which RC-approved restoration plan is considered valid?

6. R4 – Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications, …..

By inserting the previously included word “permanent” it is clear that the intent is for those permanent modifications that affect the restoration plan and not those temporary modifications that may come about due to temporary reconfiguration of the system such as may occur due to storm damage, etc.

Likes 0	
Dislikes 0	

Response

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF

Answer	No
Document Name	

Comment

R1: Recommend retaining “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System.” Helps to provide guidance for an end point to the plan.

R8. Deletion of Requirement 8 is not advised. The Reliability Coordinator must play a defined role when establishing ties. It’s the RC’s role to ensure each Transmission Operator’s System is ready for the connection.

R8.5 The Restoration Plan is not intended to go to the extent of having ACE nor AGC available. If this is required significant addition to the Restoration Plans is foreseen as not enough of the system is restored to the point where ACE and AGC will be viable. The generating units will not be in a range to be placed on AGC in the plans as written today. If training for ACE and AGC is required, then wouldn’t the restoration plans need to support same? If 8.5 is retained, recommend this requirement be trained in conjunction with a Balancing Authority Operator. This may require expanding applicability of

EOP-005 to BA?.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point: The SDT should add a conditional phrase to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: “Each Transmission Operator shall develop, maintain, and, in the event of a Disturbance, implement a restoration plan…”	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	No
Document Name	
Comment	
Austin Energy (AE) requests the SDT provide additional clarity regarding the TOP’s scope of responsibility similar to EOP-006 R1. AE offers this suggestion: R1. Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator’s System following a Disturbance in which one or more areas of the BES shuts down and the use fo Blackstart Resources is required to restore the affected area to service. Each Tranmission Operator shall implement its restoration plan when necessary to restore the portion of the BES under its control and interconnect with neighboring areas. If the Transmission Operator cannot execute the restoration plan as expected, it shall use its restoration strategies to facilitate restoration. AE requests the SDT clarify R4.2. As written currently, it may imply restoration plans must be updated prior to any outage including short-term maintenance outages. AE does not believe such an action is necessary. Other Transmission Operators and the Reliability Coordinator are notified of temporary outages through local outage-related requirements. Additionally, AE does not believe the requirement clearly defines when the plan must be updated.	

AE makes the following suggestions:

R4. Each Transmission Operator shall update, and submit to its Reliability Coordinator for Approval, its restoration plan to reflect System modifications which change its ability to implement its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modification; and

4.2. No less than 30 calendar days prior to the date on which the Transmission Operator energizes a permanent System configuration change.

Likes 0	
Dislikes 0	

Response

Tina Garvey - Austin Energy - 4

Answer	No
Document Name	

Comment

I support the comments of Andrew Gallo.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

Most training is conducted on a yearly basis, with certain training required every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required "once per calendar year." That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

The revision to EOP-005 R8 adds the requirement R8.5 - "Transition to Balancing Authority for Area Control Error and Automatic Generation Control." TVA agrees with the addition of this requirement and thinks required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn't necessarily going back to Automatic

Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control.”

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment

Comment on R3 & R3.1: ATC recognizes that FERC previously approved the retirement of R3.1. However, we recommend that the R3 language be changed to not require annual submission of the entire plan if no material have occurred. Requiring submission and RC response for these instances provides, in ATC’s opinion, little value to reliability. The standard should permit notification to the RC that the plan has not changed from the previous submission. As such, we propose that R3 be modified to read:

Each Transmission Operator shall review its restoration plan *for any substantive change,* and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually agreed, predetermined schedule *or notify its Reliability Coordinator that no sustative change occurred requiring approval of a new version of the TOP restoration plan*.

Comment on R4: As the SDT notes, TOPs should not have to submit a revised restoration plan to the RC to account for temporary changes to the system. However, the proposed edits to the standard language do not provide this clarity because R4.2 pulls in all planned modifications to the system, such as temporary configurations for construction or maintenance, that are not in view under the current EOP-005-2 R4 language. The new language pulls in these types of situations since the actual implementation of the plan in an event may be affect by construction activities (e.g., lines temporarily tied together) such that a different line gets used for a restoration path covered by R1.5 (i.e. very specific switching paths have to be identified in the plan). Today’s R4 is better suited to the realities of temporary construction activities where the plan does not need to be submitted to the RC for review because the plan already conceives of the potential for paths to not be available (see EOP-005-2 R7) such that the TOP would then use its restoration strategies to accomplish the restoration task. The SDT changes do not improve reliability. Rather, they add administrative burden without reliability benefit.

R4 recommendation: language should read “reflect *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.1 recommendation: language should read “unplanned *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.2 recommendation: language should read “planned *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

Comment on new R8.5: The proposed language for R8.5 is too specific for the standard. ATC recommends that R8.5 just read, “Transition to Balancing Authority”.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace “develop and implement” with “have”. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word ‘permanent’ into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

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Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

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Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

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In R4 we request the re-insertion of the word ‘permanent’ into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

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Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3

Answer	No
Document Name	SCANA-SCEG Survey Responses.pdf

Comment

Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer	No
Document Name	

Comment

Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	No
Document Name	

Comment

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

2. The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

A. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

B. The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Refer to #2 comments.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator." However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Operator "shall develop, maintain and implement" a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3. Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator's ability to implement its restoration plan. A definition of System modification should be added to the NERC Glossary. Or Instead of the expression "System Modifications" in R4, "BES modifications would be a better choice. The NERC Glossary definition of BES includes "Blackstart Resource" in its inclusion list. I3 – Blackstart Resources identified in the Transmission Operator's restoration plan.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Owner shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Owner “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.

Instead of the expression ‘System modifications” in R4, ‘BES modifications would be a better choice. The NERC Glossary definition of BES includes ‘Blackstart Resources’ in its Inclusion list

· I3 - Blackstart Resources identified in the Transmission Operator’s restoration plan.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy appreciates the SDT’s time and effort towards the improvement of the System Restoration from Blackstart Resources Standard and is generally amenable to the proposed revisions. CenterPoint Energy would like the SDT to consider the following changes to EOP-005-3. In R1, for consistency between the proposed EOP-005-3 and EOP-006-3 standards, CenterPoint Energy suggests the SDT align the proposed language in both R1s to be the same and use either, ”develop and implement”, or “develop, maintain, and implement”. Also, we are concerned that removal of the validation clause, “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage” expands the scope of a restoration plan. We suggest the addition of language regarding the plan’s intended function of restoring the interconnecton and recommend the following: “The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.” Without such additional language, a TOP could be expected to include in its retoration plan, steps to restore every Facility in its entire system. Furthermore, we support the retirement of R7, but believe that the language, “If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration” should be retained in the proposed R1. This language provides a TOP the flexibility to make adjustments to its restoration efforts based on Real-time System conditions and Facility availability regardless of contingency. Considering all of CenterPoint Energy’s comments R1 would state: “Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of

Blackstart Resources is required to restore the shutdown area to service. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. The restoration plan shall include:" In R4.2, to further clarify and to better align with the SDT's proposed changes in R2, we suggest the SDT replace, "No less than" with "At least" and also replace "implementation of" with "effective date of ". The requirement would then read, "R4.2. At least 30 calendar days prior to the Transmission Operator's effective date of the planned System modifications." CenterPoint Energy also believes that the proposed EOP-005-3 R8 (currently enforceable EOP-005-2 R10) along with its sub-requirements 8.1, 8.2, 8.3, 8.4, and 8.5 should be retired as they are inherent to the systematic approach to training processes. It is not that the requirements are duplicative, but rather that they are already incorporated in the training and periodicity of training that would be identified in a TOP's PER-005-2 analysis for company-specific reliability-related tasks. The criteria required to be included in the restoration plan outlined in R1.1 thru R1.9 further ensures that specific training content would be provided on system restoration and maps to the content being required in R8.1. R8.2, R8.3, R8.4, and R8.5. Retirement of R8 and its sub-requirements does not eliminate reliability-related task training on System Restoration from Black Start Resources. This rationale was applied in the recent revisions to PRC-001-1.2 (Project 2007-06.2) and industry approval of PER-006-1 to which training related requirements for the TOP were mapped out and retired. CenterPoint Energy urges the SDT to consider soliciting assistance and guidance from the PER-005 SDT and members from the training sector in the industry to assist in this matter.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) R1 now includes "develop and implement" a restoration plan for the TOP. Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including two actions, having a plan and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has nine sub-parts, which can now be reviewed under two filters – is it documented and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the nine sub-parts.

(2) We question the need for a change in R2 and R5 from "implementation date" to "effective date." They appear synonymous.

(3) We agree with the modification to R3 and R8 to remove the word "annually" and replace it with "at least once every 15 calendar months," as this aligns with several other NERC standards. We also agree with the removal of sub-part 3.1, as this was administrative in nature.

(4) Requirement R4 now requires the TOP to submit its restoration plan to the RC no more than 90 calendar days after identification of any unplanned system modification and no less than 30 calendar days prior to the TOP's implementation of planned system modifications. We question why the planned modifications were added to the requirement, as the TOP will be providing planned outages and other information to the RC already.

(5) Requirement R8 (formerly R10), added sub-part 8.5, which now includes the TOP to have training every 15 calendar months on the "transition to BA for ACE and AGC." We recommend modifying the phrase to "coordinate with the BA for restoration activities." The word "transition" could be misinterpreted that the TOP completely transfers their role to the BA in system restoration.

(6) Measure M10 (formerly M12), removed training records as proof of participation in restoration drills. Why was that type of evidence removed? It seems like the most straight-forward way to prove compliance with the requirement. Further, training records are still listed in M16 for GOP participation in restoration drills. This should be consistent throughout the standard.

Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	

R1: For the purposes of managing internal controls, and clear internal controls ownership and tracking, consider keeping this requirement as Operations Planning horizon only and then do not remove R7 and R8. Plan development and administration is an Operations Planning function. Real Time is not responsible for development and maintenance of the plan.

R4.2. Is revised to state:

4.1.4.2. No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications.

This revision takes away flexibility. Suggest that "No less than 30 calendar days prior to" be changed to "Up to 90 calendar days after implementation of planned System modifications". Planned implementation dates are often moving targets and can move earlier or later, due to construction and crew scheduling needs, and well outside of the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action.

Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	No
Document Name	FE 2015-08_EOP-005-3_IB_Comment_Form.docx
Comment	

Requirement R4: The proposed changes to R4 cause concern for FirstEnergy. The existing FERC approved requirement R4 requires notification by a Transmission Operator (TOP) to its Reliability Coordinator (RC) for a “permanent” system modification (planned or unplanned) “that would change the implementation of its restoration plan.” The proposed revisions by the drafting team, while well intended, shifts the emphasis to changes that affect “ability to implement” the TOP restoration plan regardless of whether or not the system modification (planned or unplanned) is temporary or permanent. This change would cause numerous re-writes of restoration plans by TOPs and approval reviews by RCs resulting from planned maintenance outages of BES transmission facilities (lines, transformers, generators, etc.), many of which are short duration outages. FirstEnergy believes it is important to retain the “permanent” modification aspect of the existing FERC approved requirement. The proposed change results in an overly burdensome requirement without significant improvement to BES reliability.

FirstEnergy does support the intended 90-day notification for unplanned changes and the minimum 30-day lead-time from the effective date of planned changes.

FirstEnergy proposes the requirement be written as follows:

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the implementation of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

A red-line version of our proposed changes is provide in the attached version of FE comments.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We suggest the following edit to R1 for clarity:

"R1 Each Transmission Operator shall **develop** a restoration plan approved by its Reliability Coordinator. The **implemented** restoration plan shall allow…"

We believe this better aligns with the intent and doesn't create confusion that potentially an entity must have experienced a blackout in order to fully comply (a need to 'implement') with R1.

In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

We have a concern that R6 in combination with the changes to R1 may seem to create a conflict or confusion. The changes to R1 seem to indicate the plan now covers restoration all the way up until balancing is turned over to the BA. That would seem to describe the ‘intended function’ of the plan as stated in R6. The sub-requirements in R6 seem to indicate simulation and analysis only needs to be done on energizing the Blackstart resource and connect initial loads. Perhaps R1.8 could be rephrased to better clarify the ‘intended function’ of the plan in order to better align with R6. We do not believe the intent is for dynamic simulation to be done for the entire restoration scenario all the way up to handoff to the BA in R1.9. Perhaps R6 could be rephrased such that it states:

R6 Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes **initial restoration**.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	No
Document Name	

Comment

Requirement R1: In the first sentence of Requirement R1, the proposed revision is to change the requirement that each Transmission Operator “shall have” a restoration plan approved by its Reliability Coordinator to state that each Transmission Operator “shall develop and implement” a restoration plan approved by its Reliability Coordinator. However, in order to be consistent with the language that is already been used in other requirements (see, e.g., the proposed revision in EOP-006-3, Requirement R1), the revision should state that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. Accordingly, the ISO/RTO Council Standards Review Committee (SRC) suggests that the word “maintain” be added to the proposed revision. [CAISO does not support this paragraph.]

Requirement R4: The proposed revision in Requirement R4 requires the Transmission Operator to update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that would change the ability to implement its restoration plan. The requirement, however, should be clarified to indicate that the type of System monifications that would require an update to the restoration plan are only permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan. Limiting the requirement to reflect permanent modifications is consistent with the Rationale for Requirement R4, which states that the intent of the revisions is to require the Transmission Operator to update its restoration plan when major modifications need to be made, and not to require the Transmission Operator to make updates for minor revisions. Without the qualifying word “permanent,” the proposed revision could be read as requiring updates to the restoration plan for all System modifications that would change the Transmission Operator’s ability to implement the restoration plan, even if those System modifications are not permanent (such as for planned or unplanned outages). In the event that temporary System modifications or other unforeseen system conditions prevent the Transmission Operator from implementing the restoration plan as expected, system restoration would be facilitated by implementing the restoration strategies that Requirement R1 requires to be included in the restoration plan. System modifications that would change the Transmission Operator’s ability to implement the restoration plan that are not permanent are not “major.” Requiring that the restoration plan be updated for such non-

permanent System modifications would translate into multiple, unnecessary updates to the restoration plan. For this reason, to make the requirement even clearer, the SRC suggests that the word "permanent" (which is included in the currently enforceable version of this Requirement) be added to the proposed revision. Note that, for consistency, the word "permanent" should also be added in all the Violation Severity Levels for Requirement R4. In addition, we suggest R 4.2. which currently states: "4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications" should be modified to state "4.2. Up to 90 calendar days after implementation of planned System modifications." Planned implementation dates are often moving targets due to construction and crew scheduling needs. It is well outside the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action. [NYISO does not support this comment.]	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
The stricken phrase "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." should be retained. Since R1 is specifying that the TOP shall have an SRP to restore its system, it is imperative that the TOP has a defined state at which point it knows that it has successfully achieved the requirement. The stricken language provided that. Although R1.8 contains similar language, it is in the context of information that the TOP must include in its SRP, as opposed to defining success in achieving system restoration. Compliance with R1.8 does not inform the TOP, or an auditor, that if the TOP completes the processes contained in the subrequirement, that it has successfully achieved system restoration.	
Likes 1	New York State Reliability Council, 10, ADAMSON ALAN
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Putting the word "implement" in EOP-005-3, R1: "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator", is confusing. What is meant by "implement"? Public Utility District of Chelan County (CHPD) understands "implement" to mean to put the	

Restoration Plan into effect. The Restoration Plan is not put into effect until there is a real-time event. CHPD would prefer the sentence to read: Each Transmission Operator shall develop a restoration plan and have it approved by its Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
The proposed requirement R4.2 requires TOPs to submit revised System Restoration Plans "No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications." This is not practical or advisable as it would result in the need for TOP's to submit revised Restoration Procedures to the RC which do not align with actual system configuration during the (at least) 30 day period. Restoration plans are typically "approved" procedures that reflect current configuration and have a review and approval process internal to the TOP. Approval of revisions are closely coordinated with actual implementation of system modifications to ensure that proper configuration control is maintained between procedures and the system. Having to submit a revised (and approved) procedure at least 30 days in advance of field implementation would result in procedures having to be approved and sent to an RC that do not align with actual system configuration for "extended" periods (at least 30 days). Even if an effective date is used in a TOP's procedural control process, having to assign such a date in excess of 30 days prior, would likely result in a significantly increased administrative burden due to the higher potential for date changes to occur between procedure approval and final implementation of a modification in the field. Field implementation of system modifications are subject to a degree of uncertainty due to a variety of factors (testing results, weather, system operational needs, etc). The greater the period of time between procedure revision approval and placement of a system modification in-service, increases the potential for subsequent procedure date changes being required and also raises the potential for non-alignment between Restoration Procedures and field configuration. Even if Draft Restoration Procedures are submitted to an RC, it is not clear that this would be satisfactory from a compliance standpoint for the TOP or the RC as proposed EOP-006-3 R5 requires the RC to approve a submitted TOP plan within 30 days of its receipt. It is suggested that the proposed R4.2 be changed to delete "No less than 30 calendar days" and maintain the existing requirement to submit revised, planned, Restoration plans prior to their implementation.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	

Portland General Electric Company (PGE) appreciates the efforts of the STD and being able to provide comments throughout this project. In the measure for R1 (M1) the term Disturbance is used, "…when a Disturance occurred…" Since not all Disturbances are Blackstart events, PGE suggests changing Disturbance to applicable event.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	No
Document Name	
Comment	

Compliance (Sec C.1)

We have concerns replacing "compliance audit" with "monitoring activity." The proposed term, "monitoring activity," is vague, ambiguous, and muddies the interpretation of the retention period. We can only speculate as to the reason for the change and, so, are unable to offer a suggestion to address our concern.

R2, R5, and R8

We are supportive of replacing "implementation date" with "effective date" and believe it provides added clarity.

We are supportive of replacing "annually" with "15 months" and believe it provides added clarity.

Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	
Comment	

For R3, Peak already has all the TOPs scheduled on an annual submittal process. Peak is concerned that TOPs will want to switch to a 15-month submittal process, which will be more difficult to track. Every approval will require an agreement on the next submittal scheduled rather than maintaining a known, 12-month schedule.

For R10, Can R16 be combined with R10? There are other requirements that combine various entities so not sure why participating in the RC's restoration plan would need to be separate requirements for TOPs and GOPs.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

The Purpose statement becomes an absolute positive by replacing “assure” with “ensure” therefore the restoration plan must reestablish reliability. System Operators need the flexibility to deviate from the plan in order to restore the system to precontingent operations.

Likes 0	
Dislikes 0	

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1

Answer	No
Document Name	

Comment

In R1 we recommend that the first sentence be changed from “Each Transmission Operator shall develop and implement a restoration plan approved by its Relability Coordinator.”to “Each Transmission Operator shall develop and publish a restoration plan approved by its Relability Coordinator that will be implemented folwing a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down.” The reason for this recommendation is to clarify the intention of the proposed change.

In R1, we disagree with the change after the words “… is required to restore …”. Depending upon the cause of the Disturbance (for example physical damage) that requires system Restoration from Blackstart Resources, it may not be feasible to restore the entire shutdown area of service even though the BES has been restored. We recommend leaving the original wording in place.

In R4.2, we disagree with the wording “No less than 30 calendar days prior to …” in the first sentence. We recommend changing to “Up to 90 calendar days after implementation of planned System modifications”. The reason for this recommendation is that planned implementation dates are often moving targets due to factors such as construction or equipment delays; crew scheduling needs; or other factors outside the direct control of the entity.

Likes 0	
Dislikes 0	

Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

We support NPCC's comments.

In addition, we have the following comments.

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3. However, we recommend inclusion rather than removal. Indeed, EOP-005 ‘s scope could be expanded to “System Restoration” regardless of whether Blackstart Resources are required or not. A TOP may have a major shutdown or be islanded and restore its area by synchronizing with an adjacent area. Such a TOP should nevertheless have a Restoration Plan, perform simulations as well as training. Such a change in scope would only require changes to the title and the purpose.

We note that R16 applies to Generator Operators, not Generator Operators identified in the Transmission Operators restoration plan, as was the case in EOP-005-2 R18. Most requirements in EOP-005-3 that apply to GOPs apply to GOPs with Blackstart Resources and these are identified in the TOP’s Plan. Modifying section 4.1.2. to apply only to GOP with Blackstart Resources would be consistent with EOP-006-3 R8 part 8.1 which specifies “each Generator Operator identified in the Transmission Operators’ restoration plans”. We recognize however that R16 is consistent with EOP-006-3 R8 in a general sense and also recall that in the development of EOP-005-2, comments on the same point were submitted and rejected by the drafting team at that time. If this project's drafting team rejects this comment again, **we request the addition of a rationale to clarify the purpose of this broader scope.** We note that the Régie de l'énergie here in Québec ordered a reduction of scope of R16 to the GOPs identified in the TOP plan, based on the lack of justification provided during the development of EOP-005-2 for the broader scope of R18 (now R16 in EOP-005-3).

R1: Suggest adding a rationale to explain change of scope. Does the removal of “the choice of the next Load to be restored is not driven by the need to control frequency or voltage” imply that the scope of the TOP’s restoration plan is now until all the BES is restored?

We understand that the EOP-005-3 Parts 1.9 and 8.5 that refer to transferring of Balancing Authority authority come from a FERC-NERC report. However, we believe that Balancing Authority functions always reside with the Balancing Authority. The requirement could be rephrased as a more general requirement to 'coordinate' the restoration with the appropriate BA, per RC criteria.

Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	No
Document Name	Comments on EOP 5.docx
Comment	

Likes 0	
Dislikes 0	

Response

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

For the sake of consistency I recommend considering on page 9 of 24 second line of M13 replacing the text "e-mail with" with "dated electronic". Similarly on page 10 of 24 third line of M14 the text "e-mail with" should be replaced with "dated electronic".

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:{C}[JM(1)] {C}[JM(1)]Bob H. addition	
Likes 0	
Dislikes 0	
Response	

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

FMPA generally agrees with the revisions proposed for EOP-005, but does have some comments.

R1 can still be interpreted that a TOP who would be restored via a tieline with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here?

The phrasing of R4 needs work. FMPA recommends adding commas and removing the word "of".

"Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:"

R5 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	

Comment

In spirit APS is supportive of the SDT's direction. That said, APS offers the following suggested changes with respect to the proposed wording of the standard. APS suggests the following revised wording to further clarify the language in the proposed EOP-005 standard.

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that necessitate a change in how the Transmission Operator implements its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications; and

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available to its System Operators in its primary and backup control rooms in electronic or hardcopy format prior to its effective date in accordance with Requirement R5.

In addition, APS requests the SDT clarify the text for requirement R8.5 to align the requirement language with the text in the Rationale box for R8:

R8.5 Coordination needed to transfer the following functions back to the Balancing Authority: Area Control Error and Automatic Generation Control.

Likes 0	
Dislikes 0	

Response

Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	

GRU generally agrees with the revisions proposed for EOP-005, but does have some comments.

R1 can still be interpreted that a TOP who would be restored via a tieline with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here?

The phrasing of R4 needs work. GRU recommends adding commas and removing the word "of".

"Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:"

R5 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

1. R4 Rationale: In the second paragraph the SDT may want to consider removing the word 'major' when describing System modifications as the requirement does not have this limitation, but instead deals with any System modifications that change the ability to implement the restoration plan. The use of the term 'minor' when describing revisions provides the appropriate context. Dominion also suggests the SDT could add examples into the Rationale to clarify the types of System modifications they are referring to.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance; The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
Hydro One Networks Inc. would like to inquire from the drafting team on what an auditor would be required to view as evidence for measure M1 in the case that a Disturbance has not occurred over a given period in time?	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

R1: Duke Energy recommends that the drafting team consider the following language revision to R1.

"Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator."

We think that the addition of the term "maintain" is appropriate and would promote consistency with other EOP standards.

Also, we request clarification from the drafting team about the potential for an instance of double jeoparday. If an addition to the term "maintain" to R1 is deemed appropriate by the drafting team, does that open up entities to the possibility of violating two requirements if the restoration plan is not maintained. See Duke proposed R1 language, and SDT proposed language of R4. Does the failure to maintain a restoration plan create double jeopardy with R1 and R4?

R4: Duke Energy recommends the drafting team consider revising the proposed R4 to read as follows:

"Each Transmission Operator shall update and submit to its Reliabilty Coordinator for approval of its restoration plan to reflect system modifications, that

would inhibit its ability to implement its restoration plan, as follows:"

We feel that replacing the word "change" with "inhibit" or "adversely affect/negatively impact" is more accurate representation of what is needed in this requirement. Moreover, any planned or unplanned system modification could "change" the way an entity executes its restoration plan, but an entity would still be able to execute said plan via multiple paths. We feel that the spirit of this requirement should be geared more towards system modifications that prevent an entity from executing its restoration plan altogether.

R8: Duke Energy recommends that the drafting team consider maintaining the use of the annual system restoration training, rather than using *"at least once each 15 calendar months".* We have a couple of concerns with the use of once each 15 calendar months. First, we are not aware that NERC has defined the term(s) calendar months. Some ambiguity may exist amongs industry stakeholders about what constitutes a calendar month. The use of the term "annual" is commonly used throughout the industry, and NERC has issued a Compliance Application Notice on the use of the term, and there seems to be more guidance on the tracking of annual timeframes.

R8.5: Duke Energy requests further clarification from the drafting team on how this requirement should apply to vertically integrated BA(s) and TOP(s) that are in the same control room. Also, with regards to the transition of ACE and AGC to the BA, where in the standard is it referenced when/if control was ever passed to the RC? Does this not go beyond what is outlined in R1.9? The language as written implies that a TOP was at one time in control of ACE or AGC. Not all entities may pass control over to the TOP, especially those entities that are vertically integrated, wherein the BA and TOP are in the same control room. We understand that this addition was a result of the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans, however, we don't see this change as representative of the practices of the entire industry, and can't agree with this addition based on the complication it may provide to vertically integrated companies.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	
Document Name	

Comment

PJM is concerned with the removal of the words in R1. In the proposed Standard, it is not clear when the use of the Restoration Plan should end. Adding the word "implement" to R1 and other requirements puts two actions in one requirement which makes the VSLs much more complicated. PJM has serious concerns with a misinterpretation of R6. The misinterpretation is that the entire Restoration Plan should be simulated using dynamics. That was not the intent of the SDT. Suggest adding "a combination of" before "steady state and dynamics simulations". PJM would also recommend the addition of language clarifying that Dynamic simulation is only required from Blackstart unit to cranked unit (along the cranking path), and not the entire restoration plan. Also, PJM finds the "30 day prior to implementation" wording in R4.2 is troubling. This Requirement could potentially lead to artificial delays in energizing new equipment just to meet the 30 day requirement. PJM considers the wording in the current standard ("prior to a permanent planned modification") sufficient, rather than introducing the 30 day prior requirement.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a TOP's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program.

Texas RE is concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval.

Texas RE is concerned about the proposed changes to EOP-005-2, Requirement R4. In particular, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification "that would change the ability to implement" the restoration plan. Although Texas RE does not necessarily object to the SDT's stated intent to require updates solely for material changes, the requirement to update a plan should not hinge upon the entity's perception of its corresponding "ability" to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding material modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness.

If the SDT wishes to capture a materiality threshold for required updates and submissions, however, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update "to reflect system modifications that would materially change the implementation of its restoration plan."

Likes 0	
Dislikes 0	
Response	

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Requirement 7 as it appears in EOP-005-2 is a better way to address the “implement” intent of EOP-005-3 R1.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
R7 should be retained. It is imperative that a TOP have a fallback position in the event its SRP cannot be implemented as intended. R7 specifies to the TOP that the fall back position is to utilize its strategy. For example, a TOP’s SRP might have detailed steps to restore a certain generating unit, perhaps by specifying a particular switching scheme. If the facilities to execute that scheme are not available, the TOP should still recognize the need to restore that unit, and proceed in any manner available to do so. The strategy is to restore the unit regardless of the tactics used to accomplish that. R1.1 does obligate a TOP to include it strategies in its SRP, but it does not obligate it to operate to those strategies if need be. Further, the strategies in a TOP SRP are at a more detailed level than the strategy of the RC plan in EOP-006. An RC’s plan is, in effect, it’s strategy, and is at a much higher and more general level than the TOP plan. Therefore, there is no inconsistency with retaining R7 in EOP-005 and removing it from EOP-006. R8 should be retired.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	

Please see comment in response to Q1 above.

Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

It is the responsibility of the TOP to notify the RC before resynchronization with neighbors, Southern believes that without specifically being addressed in a standard that some TOPs may not be compeled to consult with the RC before restoring tie-lines creates a potential reliability gap.

Comment for EOP-005-3 R4.1: No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications that would affect implementing the restoration plan.

Comment for EOP-005-3 R4.2: No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications that would affect implementing the restoration plan.

Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Likes 0	
Dislikes 0	
Response	

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in

EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.	
Likes 0	
Dislikes 0	
Response	
Tina Garvey - Austin Energy - 4	
Answer	No
Document Name	
Comment	
I support the comments of Andrew Gallo.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	No

Document Name	
Comment	

Unless the changes AE recommends above are implemented, R7 should not be deleted in its entirety. (See AE's response to Question 1, above) Because of the vagaries of a blackstart situation, AE believes the Standard should allow the Transmission Operator to solve issues which may not be addressed in the restoration plan. AE believes it is not possible to plan for every possible contingency and, therefore, Transmission Operators need a degree of freedom to address deviations from expectations. Therefore, AE requests the sentence "If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration" remain unless included in R1 as suggested above.

Likes 0	
Dislikes 0	
Response	

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF

Answer	No
Document Name	
Comment	

R7: . Implementation documentation should remain covered under the current Requirement 7. Focus should be on developing a restoration plan in Requirement 1 and Measurement 1 should not be confused with implementation documentation. Revise the existing R7 requirement for implementation and measures for implementation as needed.

R8. Recommend retaining or at least retaining "in accordance with the established procedures of the Reliability Coordinator". Much work has been done in this venue to provide needed guidance, and see this as an efficient way to accomplish. The Reliability Coordinator must play a defined role when establishing ties. It's the RC's role to ensure each Transmission Operator's System is ready for the connection.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We support NPCC's comments.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Reword R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control” needs to clearly state that a hand off of responsibilities are necessary at the end of system restoration.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
We are supportive of the retirements proposed in EOP-005-3 of R7 and R8.	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall "implement" a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 can, and should, be retired. [CAISO and NYISO do not support this comment]	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We understand the rationale behind the changes.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agree with the proposed retirements of R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
See comment to Question 1 proposing to retain the use of the language, “If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration”.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
What is the SDT’s thought process in removing the need for the Transmission Operator to obtain authorization of the Reliability Coordinator prior to resynchronizing its area with that of a neighboring Transmission Operator’s area under requirement R8?	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	

Answer	Yes
Document Name	

Comment

Assuming that Requirement R1 is being revised to state that the Transmission Owner shall "implement" a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 should be retired.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	

Comment

I agree with the changes however, training requred by R8.5 makes no sense if a TOP does not manage Area Control Error and/or Automatic Generation Control. My utility is a small TOP and has neither ACE management or AGC management. Training in the transition of this functionality to the BA is unnecessary since the BA provides this funcionality as part of its normal operations.

Likes 0	
Dislikes 0	

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

No.

Texas RE does not necessarily object to the SDT's proposal to retire Requirements R7 and R8 from the EOP-005-3 Standard. However, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration." As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs "resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator." Although it is perhaps possible to read R1.1's mandate that the restoration plan include "[s]trategies for system restoration that are coordinated with the [RC's] high level strategy for restoring the interconnection" as encompassing this requirement, it is not clear that resynchronization is included within either "system restoration strategies" or the RC's "high level strategy." Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator.

Texas Re noticed draft EOP-005-3 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance

Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and Enforcement Program. There is no section for Reset Time Frame, Compliance Monitoring and Enforcement Processes, or Additional Compliance Information.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
The word “neighboring” should be replaced with the word “electrically adjacent” in all instances in the standard (including the Violation Severity Levels). “Electrically adjacent” lends more clarity to the intent of the requirements than “neighboring.” It is suggested that the below changes be made to Part 4.1 so that it reads: “If a Reliability Coordinator finds conflicts between its restoration plan and the restoration plan of an electrically adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar-days of written notification of the identified conflicts from the Reliability Coordinator to the adjacent Reliability Coordinator.” The additional revisions clarify that both the initiating Reliability Coordinator, and the electrically adjacent Reliability Coordinator have to resolve any conflicts. The timing for resolution of the conflicts will also be made clear.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Consider revising R3 to allow "Annual" review to be consistent with other NERC standards. The verbiage change from "Annual" to "at least every 15 months" in R7 is unnecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	
The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point: Similar to the comment for Question #1, we ask that a conditional phrase be added to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: "Each Reliability Coordinator shall develop, maintain, and, in the event of a Disturbance, implement a Reliability Coordinator Area restoration plan." If the SDT intends there to be a difference in meanings of the words "adjacent" and "neighboring," we request that this difference be explained and made more explicit in the language of the standard. We also ask for clarification on the meaning of the phrases "adjacent Transmission Operators" and "adjacent Reliability Coordinators," for the ERCOT interconnection, as neither of these terms is defined. We ask the SDT to clarify that, consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, "adjacent" should not be read to apply to RCs or TOPs that are not "within the same Interconnection." This change is appropriate because ERCOT does not rely on SPP or MISO for system restoration, and SPP and MISO also do not rely on ERCOT for that purpose.	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	

Most training is conducted on a yearly basis, with certain required training every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required “once per calendar year.” That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around from year to year as needed.

EOP-006-3 R1 states, “Each Reliability Coordinator shall develop, maintain, and implement” while EOP-005-5 R1 states, “Each Transmission Operator shall develop and implement.” We recommend that the “develop and implement” language in EOP-005-3 R1 be used in EOP-006-3 R1 for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

R7: See Duke Energy’s comment regarding the replacement of “annual” with “at least once each 15 calendar months” in response to question 1 above.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

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Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment	
We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly. We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as: R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly. We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as: R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.	
Likes 0	
Dislikes 0	

Response	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	

Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement.

EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement.

We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

2. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement. EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

A. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

B. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement..EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend ‘develop and implement’ language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Requirement 8 should NOT be retired. It is a critical step in the Restoration Plan that requires RC approval.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Document Name	
Comment	

(1) R1 now includes “develop, maintain, and implement” a restoration plan for the RC. We question why “maintain” was included in EOP-006-3, but it only states “develop and implement” for the TOP in EOP-005-3. This is inconsistent language and should be aligned.

(2) We disagree with the inclusion of “maintain and implement.” Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including three actions, having a plan, maintaining the plan, and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has six sub-parts, which can now be reviewed under three filters – is it documented, is it maintained, and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the six sub-parts.

(3) For R3, we agree with the change from 13 calendar months to 15 calendar months to align with other NERC standards.

(4) For R7 (formerly R9), we agree with changing annual to 15 calendar months to align with other NERC standards.

Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2

Answer	No
Document Name	
Comment	

Please see our response to Q1 regarding R1 of EOP-005-3 which we feel are applicable to EOP-006-2 as well.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	

It seems that there was inconsistent use of ‘maintain’ in R1 between EOP-006-3 and EOP-005-3. We suggest removing the word ‘maintain’ in R1 since it is redundant with requirement R3. Also M1 would need to be edited to measure that the plan was appropriatel ‘maintained’ as well as implemented. As stated, it does not verify that the plan was maintained.

In the revised R1.2 we just point out that there can be ‘adjacent’ entities that may not be within the same Interconnection (example: SPP BA/RC and

ERCOT BA/RC) that it may not be appropriate or necessary to coordinate restoration plans. One way to handle this may be to specify that coordination must be performed with entities within the same Interconnection, or alternatively allow the restoration plan to dictate which entities are considered adjacent.

We believe the intent of the proposed R8.1 is to only require participation by TOPs and GOP's who 'have a role' in the restoration plan. There are TOPs and GOP's in the RC Area who may never have a role in restoration activities (aka wind farms or small TOPs). We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each Transmission Operator **which has a role** in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least **once** every two calendar years.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	No
Document Name	

Comment

In Requirement R1.2, the proposed revisions establish that the restoration plan must include criteria and conditions for re-establishing interconnections with other Transmission Operators within the Reliability Coordinator's Area, with "adjacent" Transmission Operators in other Reliability Coordinator Areas, and with "adjacent" Reliability Coordinators. The use of the word "adjacent" is more appropriate as it makes the requirement more clear. The SRC suggests a further clarification that is consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, which states that "adjacent" should not be read to apply to RCs or TOPs that are not "within the same Interconnection." The SRC suggests that the words "electrically adjacent" be used throughout the standard. Specifically, the word "neighboring" should be replaced with the word "electrically adjacent" in all instances in the standard (including the Violation Severity Levels), because "electrically adjacent" is clearer than "neighboring"or "adjacent" (alone).

In addition, the SRC suggests that clarifying changes be made in Requirement 4, Part 4.1, so that it reads as follows:

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and the restoration plans of an adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar days of written notification from the Reliability Coordinator to the adjacent Reliability Coordinator of the identified conflicts.

The additional revisions make clear that both the Reliability Coordinator and the adjacent Reliability Coordinator have to resolve any conflicts, and the timing for resolution will also be clear.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
see comments from IRC/SRC	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a RC's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program.

Texas RE recommends clarifying the Reliability Coordinator's obligations to "maintain" a restoration plan. As currently drafted, neither the measure nor VSLs specifies the evidence or severity of an issue associated with the failure to maintain. One possible interpretation of this requirement is that RC's must use the proposed 15 month reviews to ensure their plan includes appropriate criteria and processes for the re-energization of shutdown areas. However, it possible that RCs may have additional or distinct obligations. Texas RE requests that the SDT provide additional information regarding maintenance obligations under this requirement.

Texas RE recommends defining the terms "neighboring" and "adjacent". It is unclear whether or not there is a difference in what those terms mean. Requirement R1 has "neighboring" RC reference but Requirement part 1.2 has "adjacent" referenced. In 4.1 "neighbors" is used (and is assumed to RCs). There appears to not be a requirement to provide the RC plan to neighboring/adjacent TOPs There should be consistency in terms used and it should be well understood by all RCs that adjacent/neighboring is the RC (or RCs) that is (are) touched at the boundary regardless of synchronous or asynchronous connectivity.

Texas RE is concerned that, without parts 1.2,1.3, and 1.4, there may not be clarity provided in roles and responsibilities within a restoration plan. There should be Operating Processes utilized by the RC.   The restoration plan should clearly indicate coordination efforts with TOPs and RCs. In the proposed 1.2 (old 1.5) there is a reference to "adjacent" TOPs in other RC Areas but no requirement to provide the RC restoration plan to those adjacent TOPs (nor a requirement for the adjacent RC to provide the plan). This appears to be a gap in reliability if there are criteria for "reestablishing interconnections" with TOPs in other RC Areas. It is unclear whose role or responsibility it is that to provide the information.

Texas Re noticed draft EOP-006-2 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and Enforcement Program. In the EOP-006-2 draft, compliance Enforcement Authority does not have a section. The reset Time Frame and Evidence retention is section C 1.1. C1.2 is Compliance Monitoring and Enforcement Processes Program (incorrect section and title)

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	

Comment

There are multiple references to "neighboring RCs" in the Standard. Can these all be replaced, as appropriate, with the word "adjacent RCs?" If the intent as referenced with the change in R1.2 holds true to the whole Standard then clarifying neighbors to be "direct connection" instead of "just neighbors without electrical adjacency." This is particularly true for R4 – is it really necessary for Peak to review MISO's Restoration plan now that we have no electrical connection with them?

Old R10.1 (new R8.1): Peak seeks clarification – shouldn't the new R8.1 follow the same logic of 15 months instead of 24 months so as to keep it in line with new R7 (internal restoration drill training)? Or is the intent that every 15 months RCs train internally but only every 24 months they invite all TOPs and GOPs?

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

We support NPCC's comments.

In addition, we have the following comments.

M4 does not reflect the written notification time requirement (60 days) in R4. We suggest :

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans, **has provided written notification of any conflicts within 60 calendar days** and resolved any conflicts within 30 calendar days of notification in accordance with Requirement R4.

The VSL table for R4 does not address situations where the RC reviews the submitted plans but does not provide written notification of a conflict. (in those situations, the timer for the resolution of conflicts between the plans never starts.)

We note that requirements 1 and 2 refer to the 'RC Area restoration plan' whereas the rest of the requirements skip 'Area'.

Likes 0	
Dislikes 0	

Response

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	Yes
Document Name	

Comment

FMPA generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
GRU generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

1. For additional clarification, Dominion suggests the following changes to R4; Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered between restoration plans during that review within 60 calendar days of receipt.
2. In Part 4.1, Dominion suggests the following change to clarify when the 30 day period starts:

If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of delivery of written notification.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance: The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy believes that for consistency between the EOP-005-3 and EOP-006-3 proposed standards the language proposed in both R1s should be consistent and use either, ”develop and implement”, or “develop, maintain, and implement”.	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 6

Answer	
Document Name	

Comment

EOP-006-3 does not apply to AE and, therefore, we have no opinion.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

No Opinion.

Likes 0	

Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Document Name	
Comment	
This standard is not applicable to Hydro One Networks Inc.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	
Document Name	
Comment	
EOP-006-2 is applicable to Reliability Coordinators only. CHPD is not registered as a Reliability Coordinator. As such, CHPD does not have an opinion.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
RC only.	
Likes 0	
Dislikes 0	

Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
R7 requires at least once each 15 calendar months, annual System restoration training for its System Operators. R8 requires two System restoration drills, exercises, or simulations per calendar year. Need to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
Please see comments above which apply to EOP-006 as well.	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The Violation Severity Level should match the proposed Standard EOP-006-3 Requirement R8 instead of Requirement R8.1.	
Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment

One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	

Comment

1. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No

Document Name	

Comment
One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment
See comments to #2

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment
See comments to #2

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to #2	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to #2	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Because lack of coordination could have such a large impact on system reliability during system restoration, the requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization with neighboring TOPs and RCs.	
Likes 0	

Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	No
Document Name	
Comment	
See answer to Number 2.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
R7 requires System Operator training every 15 months and R8 requires two drills, exercises or simulations every calendar year. The NSRF requests that R7 and R8 be combined to to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The SDT can add in the sub-Requirements to capture all concerned parties. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We support NPCC's comments.	
Likes 0	

Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
We are supportive of the retirements proposed in EOP-006-3 of R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall “implement” a Reliability Coordinator Area restoration plan, Requirements R7 and R8 can, and should, be retired. [CAISO and SPP do not support this comment.]	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agree with the proposed retirement of R7 and R8.	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

1. New M7: Remove the additional ‘M7’, that is listed above R7
2. New M8: The request to participate is applicable to part 8.1 only in the last sentence, therefore Dominion suggests the last sentence in M8 be written to read as; And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement 8 Part 8.1.

Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

Assuming that Requirement R1 is being revised to state that the Reliability Coordinator shall “implement” a Reliability Coordinator restoration plan, Requirements R7 and R8 should be retired.

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Consistent with the comments in response to Question 2 above on EOP-005, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration." As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate:

1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to "coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization." Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC's restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC's existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following:

1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators

Likes 0	

Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	
Document Name	

Comment

This standard is not applicable to Hydro One Networks Inc.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

No Opinion

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 6

Answer	
Document Name	

Comment

EOP-006-3 does not apply to AE and, therefore, we have no opinion.

Likes 0	
Dislikes 0	

Response

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R5 and R7 is unecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SRP recommends clarifying the revision of the next to last bullet of Section 1.2 Evidence Retention. How many previous calendar years is evidence to be retained for?

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

EOP-008 R5.1 has always been a bit ambiguous as to when it triggers a required update of the Operating Plan. “Any changes to any part of the Operating Plan” could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle. Langaue could be modeled off the new language in EOP-005-3 R4. For example, the language could be changed to, “An update and approval of the Operating Plan for backup functionality shall take place withing sixty calendar days to reflect changes in the operating plan to items

in R1 that would change the ability to implement the operating plan.”	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
R1: We request further clarification regarding the inclusion of Interpersonal Communications in R1.2.3. Will the the Operating Plan for backup functionality need to also address Alternative Interpersonal Communications? The primary control center for the BA/TOP is required under COM-001-2.1 to have both Interpersonal Communications and Alternative Interpersonal Communications. To follow R1.3, it seems like BA/TOP entities would need to also have Alternative Interpersonal Communications addressed in the Operating Plan for EOP-008-2 in order to keep backup functionality consistent with the primary control center. Also, when operating from the backup, entities still must adhere to Standard COM-001-2.1. If Alternative Interpersonal Communications need to be part of the Operating Plan for EOP-008-2 that should be clear to all entities from the Standard so they know what their obligations are. The current version just says Voice communications, and that can mean something very different than having both Interpersonal Communications and Alternative Interpersonal Communications. R5: See Duke Energy’s comment regarding the replacement of “annual” with “at least once each 15 calendar months” in response to question 1 above.	
Likes 0	
Dislikes 0	
Response	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	
“Any changes to any part of the Operating Plan” could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.

Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.

Likes 0	
Dislikes 0	
Response	

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	

PGE thinks that the 15 month window is too restrictive and will give us less flexibility to schedule the drills outside of storm season, peak load periods, unexpected issues, etc. There is little gained by the more restrictive window, and much flexibility is lost in the ability to work around system demands.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	Yes
Document Name	

Comment

The replacement of “annual” with “at least once each 15 calendar months” in R7 introduces additional unnecessary administrative tracking requirements, suggest that this requirement remains an annual requirement.

Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro suggests to keep using Voice communications for R1.2.3 as it provides more clarity than Interpersonal Communications and eliminates redundancy with R1.2.2. Other type of communication mediums such as email and web messaging would already be covered under R1.2.2 Data communications.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes

Document Name	
Comment	
GRU generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We believe the SDT should add language "with respect to loss of control center functionality" in Requirement 7 immediately after "Operating Plan"	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM has concerns with R6 and its implecations to other standards. Specifically, TOP-001-4 and its requirement to maintain redundancy.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	

Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	
Comment	
CenterPoint Energy generally agrees with and supports the SDT's revisions and clarifications proposed for EOP-008-2. We would like the SDT to consider changing R1.2.2 from, "Data communications" to "Data exchange capabilities" for consistency and alignment with revisions to the upcoming January 2017 enforceable requirements in TOP-001-3 R19 and IRO-002-4 R1 which are required to support the data specification concept in TOP-003-3.	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	
Comment	
(1) We agree with the R1 changes from voice communications to Interpersonal Communication capabilities to align with other NERC standards. (2) We question the need for a change in M1, M2, and M5 from "in force" to "in effect." They appear synonymous. (3) For R5 and R7, we agree with changing annually to 15 calendar months to align with other NERC standards.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6,

5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

R1

We agree the revision to R1, Part 1.1. prevents a tertiary Requirement (i.e., already included in EOP -008- 2, R3 and R4).

We agree that in R1, Part 1.2.3., the defined term "Interpersonal Communications" should be used.

R5 and R7

We are supportive of replacing "annually" with "15 months" and believe it provides added clarity.

Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

We agree with EOP-008-2

Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

Given the shift in EOP-005-3 and EOP-006-3 away from the mere 'having' a restoration plan to 'developing and implementing' a restoration plan, would it make sense to shift EOP-008-2 R1 away from 'having' to 'developing and maintaining' the Operating Plan? The other requirements concerned with the physical plan remain valid.

Should R7 be modified to ensure consistency with R1.5 time requirement?

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality **is less than or equal to two hours**.

7.2. The backup functionality for a minimum of two continuous hours.

Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tina Garvey - Austin Energy - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wes Wingen - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Requires a rework of the language related to the retention of evidence as “previous calendar years” is ambiguous and open to interpretation. Recommend that language related to the retention of evidence be consistent throughout the NERC standard. That is, “…shall retain evidence for the time period since its last compliance audit.”	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The term “control center” (Purpose statement, Requirement R1, part 1.3, part 1.5, part 1.6, Requirement R2, Measure M2, Requirement R3, Measure M3, Requirement R4, Requirement R6, Measure M6, part 7.1, Evidence Retention section, and the VSL section) should be capitalized as it is a defined term. Texas RE recommends revising Requirement R2 to generically refer to any location capable of providing backup functionality as there are cases where there are tertiary control centers developed. Note that having multiple locations where backup functionality may exist is considered to be, or could be considered to be, an exceptional step in supporting reliability and continuity of reliable operations but there should be an expectation of similar reliability expectations coupled with compliance obligations at these locations.	

As the goal of the Reliability Standards is Reliability, Texas RE recommends revising Requirement R3 and Requirement R4 “reliable operations and subsequent compliance…”

Texas RE suggests Requirement R3 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "certified Reliability Coordinator operators" with System Operator, which is defined.

Texas RE suggests Requirement R4 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "applicable certified operators" with System Operator, which is defined.

In the “Evidence Retention” section, the changes made to the Measures do not seem to have been provided here (e.g. Measurement M1 changed “in force’ to “in effect” below the R1 but in this section still shows “in force”…multiple instances that need a quality review). Additionally there is inconsistency in the language (e.g. audit versus compliance activity) in this section as compared to EOP-005.

Likes 0	
Dislikes 0	

Response

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
We support NPCC's comments.	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	No
Document Name	
Comment	
The SRC suggests that the VSLs for EOP-00-3 be clarified as follows: R1 – Severe VSL: The Transmission Operator does not have an approved restoration plan OR The Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1. R3 – Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words “or confirmation of no change” in all of the VSLs to make the language consistent with the deletion of Requirement R3.1.	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) For the requirements that added “implement” to the requirement, we disagree with the corresponding changes to the VRFs and VSLs. The reasons for disagreement are captured in previous comments.

(2) For the requirements that were proposed to be retired or requirements that had timelines clarified, we agree with the corresponding VRFs and VSLs.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

EOP-005-3 R3: Adjust the VSLs to match R3 due to the striking of R3.1.

EOP-005-3 R4: **Moderate VSL:** The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 91 calendar days and 120 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator at least 20 calendar days prior to a **planned** change.

EOP-005-003 R4: **High VSL**: The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 121 calendar days and 150 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation to the Reliability Coordinator at least 10 calendar days prior to a **planned** change.

EOP-005-003 R4: **Severe VSL:** The TOP has failed to update and submit its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator within 150 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator prior to a **planned** BES modification.

EOP-006-3 R8: The VSL should match the Standard Requirement R8, not R8.1.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
R4: Duke Energy suggests that the drafting team revisit the language for Severe VSL for R4. It appears that the phrase *"to a planned BES modification"* was left in the VSL, whereas the language used in the other VSL(s) use *"to a planned change".*	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC).	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
For EOP-005-3 R1 and EOP-006-2 R1 Severe VSLs, SRP recommends removing the verbiage regarding implementation of the plan. For EOP-005-3 R2, the first 3 VSLs are based on a discrete number, while the Severe VSL also includes the term "half". That causes a potential for contradiction. For example, if an approved restoration plan only identifies 2 entities and 1 of them is not notified of changes, that meets the criteria for both the Lower VSL and the Severe VSL.	
Likes 0	

Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

ReliabilityFirst provides the following comments for the **EOP-005-3** VSLs:

1. VSL for R1
   i. Requirement R1 has 9 sub-parts but the high VSL only mentions missing 3 sub-parts. This leaves a gap in cases where an entity fails to comply with 4 or more sub-parts. RF suggest the following as an additional "OR" VSL to the Severe VSL
      a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.
2. VSL for R6
   i. To further clarify the timing of the High VSL, RF recommends the following modification for the High VSL:
      a. The Transmission Operator performed the verification but did not complete it within [six years].
3. VSL for R8
   i. Since Requirement R8 has a timing component as well "…training at least once each 15 calendar months…", RF recommends adding additional "OR" VSLs to the Severe VSL level as follows:
      a. Severe VSL - The Transmission Operator failed to include within its operations training program, System restoration training at least once within 15 calendar months for its System Operators.
4. VSL for R12
   i. To be consistent with the language in Requirement R12, RF recommends the following language for the Severe VSL
      a. Each Generator Operator with a Blackstart Resource failed to have documented procedures for starting each Blackstart Resource and energizing a bus.

ReliabilityFirst provides the following comments for the **EOP-006-3** VSLs:

1. Requirement R2
   i. RF request clarity around the phrase "or revision" at the end of Requirement R2. Since the RC must perform a review of the restoration plan every 15 calendar months according to Requirement R3, is this considered a revision (thus prompting the RC to distribute the restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days)? If this is the intent, RF recommends the following revision for the SDTs consideration.

a. R2 - The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation, revision [or annual review].

1. VSL for R5
2.

i. Since the word “notification” is not in Requirement R5, RF suggests removing the second “OR” VSL from each of the VSL Categories and add the phrase “with stated reasons” to the first VSL. Listed below is an example of this addition to the Lower VSL Category:

a. The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans [with stated reasons] from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt.

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

It is suggested that the VSLs for EOP-005-3 be revised for clarification as follows:

R1--Severe VSL: The Transmission Operator does not have an approved restoration plan OR the Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1.

R3--Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words “or confirmation of no change” in all of the VSLs to make the language consistent with the deletion of Part 3.1.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF

Answer	Yes
Document Name	

Comment

Note the SDT will need to make changes to EOP-005-3 VSLs to align with FE proposed requirement text changes if the changes are accepted.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	Yes
Document Name	

Comment

No comments

Likes 0	

Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment

EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	

Comment

EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	Yes

Document Name	
Comment	

EOP-005-3:

All R3 VSLs should be revised to read as ‘mutually agreed upon’.

R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

Comments: EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tina Garvey - Austin Energy - 4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

EOP-005: Consistent with Texas RE's comments above, the SDT should separate the development and implementation of restoration plans under EOP-005-3's requirements. If the SDT does this, these changes should also flow through the affected VSLs. However, the SDT should at a minimum revise the language in the VSL to reference the revised standard requirements in R1. That is, the VSL, as currently drafted, uses the term "comply." Rather, as Texas RE reads the elements in the VSL, the Lower, Medium and High categories reference a TOP's obligation to incorporate the various restoration plan elements specified in parts R1.1 through R1.9. As such, Texas RE recommends revising the VSLs to make clear that the each violation threshold applies for TOPs not including required elements in their plan. For example, the Lower VSL should read: "The [TOP] has an approved plan, but the plan is missing one of the required elements specified in the requirement parts within Requirement R1."

EOP-006: Please see the comments on EOP-006-3, R1 above. The proposed VSLs do not address a RC's maintenance obligations under R1.

EOP-008: The Requirement R2 Severe VSL should say "control locations".

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

In EOP-005-3 the effective date of the restoration plan should be defined. Requirement R4 only takes into account the update and the submittal of the TOP plan to the RC for approval. Requirement R4 does not define the effective date of the TOP plan. On reading between the lines, it can be understood that the restoration plan should be effective no more than 120 (90+30) days following an unplanned System modification and prior to the implementation of a planned System modification.

The Drafting Team should consider the addition of a phrase to Requirement R4 to indicate that the TOP plan becomes effective following its approval by the RC.

Requirement R6 of EOP-005-3 requires verification and testing of the restoration plan at least once every five years.

The *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans* recommended the re-verification or re-testing of the restoration plan when there are System changes that could impact the viability of the plan.

The Drafting Team should consider the updating of Requirement R6 according to the recommendation or explain why this recommendation was not retained.

The phrase “or an energized island has been formed on the BES within the Reliability Coordinator Area” needs to be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3.

The spirit of this standard applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators. Does the “energized island” refer to an island formed that bridges boundaries between two TOPs or an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island solely in the context of a partial outage?

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	

EOP-005-3 in Section C, 1. Compliance Monitoring Process, that the data/retention time frame for R1 (first bullet) is since the “last monitoring activity”. This is a moving target for tracking evidence retention. EOP-006-3 does not have the same retention period for the RC similar Requirement. It remains as the “last compliance audit”. Would suggest that the drafting team return the retention language for EOP-005-3 R1 back to the ‘last compliance audit’.

Likes 0	

Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	
Document Name	
Comment	
Not applicable.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	

The webinar for Project 2015-08 mentioned that the proposed revisions to EOP-005 and -006 to address the Recommendations from the ***FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.*** In that regard, Recommendation #2 stated:

2. Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits. In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new blackstart generator location or on redefinition of a cranking path). **[Section IV.G]**

R6 states that: "Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years…."while **M6** goes on to state that: "Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with **R6**."

If the SDT's intent is to have the Transmission Operator verify its plan following an update triggered by **R4**, then APS recommends requirement R6 be revised to more clearly indicate this expectation as follows:

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years or as triggered by a revision to its restoration plan following a System modification as defined under requirement R4. Such analysis, simulations or testing shall verify:…"

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	
Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
The two separate postings caused confusion because the same project has different due dates and overlapping comment periods. We strongly recommend delaying the posting until all standards are ready. We have concerns that the announcements to industry were not clearly announced and stakeholders may not be aware of the two separate and distinct deadlines for submitting comments and balloting on this project. Thank you for the opportunity to comment.	

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	
Document Name	

Comment

ISO-NE voted Negative on EOP-005-3 and EOP-006-3; this is in support of comments submitted here as a member of the SRC; if comments submitted are addressed, ISO-NE would be supportive of the revised Standards.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	
Document Name	

Comment

1. In R2 and M2 of EOP-005-3, it is not clear who "their" is referring to in each statement.

2. There are several references to 15 calendar months throughout EOP-005-3. Changing the time period to 15 months does not enhance reliability but does have other negative impacts. In R3, entities already have a set period identified by their RC as to when their restoration plans are due. In R8, changing the requirement from annually to 15 months adds a significant level of complexity by requiring tracking of individual rolling time windows for each operator.

3. In R8.5 of EOP-005-3, training operators on the transition back to normal operations does not provide a reliability benefit commensurate with the level of effort required to develop training. In addition, operator training content is established using the Systematic Approach to Training as required by PER-005-2, R1. Adding training requirements outside of SAT and the PER standard is contrary to the intent of PER-005 and the philosophy of the systematic approach.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	

Document Name	
Comment	

Texas RE noticed EOP-005-3 Requirement R2 only appears to only apply when there is a change to entities' roles. Texas RE is concerned those entities where there is not a change would not receive an updated restoration plan and thus have a different plan than other entities. Texas RE recommends providing an updated restoration plan to all entities identified in the plan if there are any changes to the plan. There should be information indicating a change or "no change" in the roles.

Texas RE noticed the term "system" is not capitalized in EOP-005-3 Requirements R1.1 and R1.2, but it is capitalized in the RSAW. Since "system" is a defined term in the NERC Glossary, and to be consistent with the RSAW, Texas RE recommends capitalizing the term.

Texas RE noticed EOP-005-3 is uses the term "Disturbance" but EOP-006 has no reference to a "Disturbance". Texas RE inquires as to why EOP-006-3 does not mention "Disturbance".

Texas RE is concerned with the language in EOP-005-3 Requirement R9 that says: "that are outside of their normal tasks". Specific system restoration training should always take place regardless of whether or not the unique tasks are outside [System Operators'] normal tasks". Texas RE is concerned training might not take place if registered entities do not consider System restoration a unique task.

Texas RE requests, in the future, that a full redline be provided for every project. If it is not clear what changed, the requirement language cannot be fully evaluated. Also, Texas RE requests rationale for the changes.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
We support NPCC's comments. In addition we have the following comments. Comments regarding EOP-006-3 and the concept of "energized island": The phrase “or an energized island has been formed on the BES within the Reliability Coordinator Area” should be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3. As argued in question 1, we support this concept in EOP-006-3 and would like this concept extended to EOP-005-3. However, we would like the concept to be clarified in order to set clear expectations and a common understanding around this concept. We note, for example, that the spirit of EOP-006-3 applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators. RC- RC : As phrased, would an island on the BES that lies across two RC boundaries trigger R1? The third sentence implies the affirmative. If so, it could be clearer to replace the "within the RC Area" by "within **or partly within** the RC Area" or some other variant. RC -TOP : Does the concept of “energized island” distinguish an island that bridges boundaries between two TOPs and an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island in R1 solely in the context of a partial outage?	
Likes 0	
Dislikes 0	
Response	

<u>Comments on EOP-005-3 – System Restoration from Blackstart Resources</u>

EOP-005-3 R1:

Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shuts down~~ shutdown area to service. ~~To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.~~

Comment:

a) The wording *"develop and implement"* has led to some confusion among entities who only see the requirement (the first sentence) and do not take into account the rest of the requirement and also the measurement of compliance associated with the requirement.

   M1 states: Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other communication documentation to show that its restoration plan was <u>implemented</u> for times when a Disturbance has occurred, in accordance with R1.

   Recommend improved language for EOP-005-3 R1 to alleviate the confusion and provide clarity for the requirement. Such as "maintain" or "make effective," in any case, I believe that the SDT should further define the meaning of "implement" in the requirement.

b) Keep the language *"To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System."* As *"to restore the ~~shuts down~~ shutdown area to service,"* could have broader implication for restoration of every part of the system down to what level of distribution?

EOP-005-3 R9:

*Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as **performing unique tasks associated with the Transmission Operator's restoration plan that are outside their normal tasks.***

Comment:

a) Recommend improved language adding clarity to the term "unique tasks" – what does this mean? Does this mean restoring islands, synchroscopes, and restoring station power? Or?

<u>Comment on EOP-006-3 – System Restoration Coordination</u>

a) This NERC standard is applicable to Reliability Coordinators therefore I have no comments.

<u>Comment on EOP-008-2 – Loss of Control Center Functionality</u>

See *Draft 1 of EOP-008-2 June 2016:* "Section C. Compliance 1.2 Evidence Retention Bullet #7 page 8 of 15"

Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current and previous calendar years ~~and one previous year,~~ such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement 7.

Comment:

a) Requires a rework of the language related to the retention of evidence as "previous calendar years" is ambiguous and open to interpretation. Recommend that language related to the retention of evidence be consistent throughout the NERC standard. That is, "…shall retain evidence for the time period since its last compliance audit."

SCANA/SCE&G Survey Responses

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   No

   Comments:

   a. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

   b. The revision to EOP-005 R8 adds the requirement R8.5 "Transition to Balancing Authority for Area Control Error and Automatic Generation Control." We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn't necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, "Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control"

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   No

   Comments:

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:

a. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

b. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement..
EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement..
We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:

a. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:

"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Yes

Comments:

EOP-005-3:

a. All R3 VSLs should be revised to read as 'mutually agreed upon'.
b. R4: High VSL should be revised to read as 'between 121 calendar days and 150 calendar days…'.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Comments: None

Unofficial Comment Form

2015-08 Emergency Operations

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Opreations; EOP-005-3 – System Restoration from Blackstart Resources, EOP-006-3 – System Restoration Coordination, and EOP-008-2 – Loss of Control Center Functionality**. The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Standards Developer Manager, Sean Cavote (via email), or at (404) 446-9697..

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT) that resulted from the PRT's review of a subset of EOP Standards. The PRT comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous.

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 –Revise the standard; and
- EOP-008-1 – Revise the standard.

The four NERC Reliability Standards in the Periodic Review project concerned methodologies for restoring, reporting, and communicating Emergencies. Implementation of revisions and retirements recommended by the EOP PRT clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards, while making the standards more Results-based.

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

☐ Yes
☒ No

Comments:

Requirement R4: The proposed changes to R4 cause concern for FirstEnergy. The existing FERC approved requirement R4 requires notification by a Transmission Operator (TOP) to its Reliability Coordinator (RC) for a "permanent" system modification (planned or unplanned) "that would change the implementation of its restoration plan." The proposed revisions by the drafting team, while well intended, shifts the emphasis to changes that affect "ability to implement" the TOP restoration plan regardless of whether or not the system modification (planned or unplanned) is temporary or permanent. This change would cause numerous re-writes of restoration plans by TOPs and approval reviews by RCs resulting from planned maintenance outages of BES transmission facilities (lines, transformers, generators, etc.), many of which are short duration outages. FirstEnergy believes it is important to retain the "permanent" modification aspect of the existing FERC approved requirement. The proposed change results in an overly burdensome requirement without significant improvement to BES reliability.

FirstEnergy does support the intended 90-day notification for unplanned changes and the minimum 30-day lead-time from the effective date of planned changes.

FirstEnergy proposes the requirement be written as follows:

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the implementation of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

A red-line version of our proposed changes is provide in the attached version of FE comments.

FE Propopsed R4 - Redline to Draft 1: R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the ~~ability to~~ implemention of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] 4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications. 4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:
   Note the SDT will need to make changes to EOP-005-3 VSLs to align with FE proposed requirement text changes if the changes are accepted.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

   Comments:

Consideration of Comments

Project Name:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2
Comment Period Start Date:	6/30/2016
Comment Period End Date:	8/15/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 NBP IN 1 NB

There were 64 sets of responses, including comments from approximately 141 different people from approximately 75 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Questions

1. **Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.**

2. **Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.**

3. **Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.**

4. **Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.**

5. **Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.**

6. **Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.**

7. **Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC

					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Stan Rzad	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC

					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC

					Paul Mehlhaff	Sunflower Electric Power Corporation	1	SPP RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO

					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO

					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company Services, Inc	1	SERC
					John Ciza	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Robert Coughlin	Robert Coughlin		NPCC	SRC	Kathleen Goodman	ISO-NE	2	NPCC
					Ben Li	IESO	2	NPCC

NERC

					Greg Campoli	NYISO	2	NPCC
					Mark Holman	PJM	2	RF
					Liz Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ali Miremadi	CAISO	2	WECC
					Terry Bilke	MISO	2	RF
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion and NYISO	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC

Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	UI	3	NPCC
Michele Tondalo	UI	1	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Si Truc Phan	Hydro Quebec	2	NPCC
Silvia Parada Mitchell	NextEra Energy	4	NPCC
Helen Lainis	IESO	2	NPCC
Laura Mcleod	NB Power	1	NPCC
Brian Shanahan	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
MIchael Forte	Con Edison	1	NPCC

					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen M. Goodman	ISO-NE	2	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schimtt	Nebraska Public Power District	1,3,5	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Michelle Corley	Cleco	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
Lower Colorado River Authority	Teresa Cantwell	1		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE

					Teresa Cantwell	LCRA	1	Texas RE

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Thomas Foltz - AEP - 5	
Answer	No
Comment	

While AEP supports the overall direction and efforts of this project team, we have chosen to vote negative on EOP-005-2. Our negative vote is driven by our concerns regarding the obligation to reissue the entire restoration plan 30 days prior to the Transmission Operator's implementation of planned System modifications, even for minor revisions.

The proposed thirty-day window in R4 would be a difficult time frame to meet in many instances. Many jobs that are not directly created for the restoration plan, yet affect its restoration sequence, are often scheduled. However, these jobs are often rescheduled due to weather, system conditions or conflicting scheduled outages. Due to the possibility of multiple system improvements that may occur, which are either completed ahead of schedule or delayed during those 30 calendar days, we believe an accurate plan could not be maintained for the system operators. One option would be an addendum sheet that would contain the incremental changes and their implementation date, which could then be followed by a quarterly update to the restoration plan. This addendum sheet would be provided to all of the RTO and all the affected parties.

As the restoration plan is a voluminous document, AEP proposes to communicate with the RC only on the incremental changes (which could be only few sentences) rather than reissuing the entire, voluminous document.

AEP suggests modifying the proposed revision of R4 as suggested above, as well as completely eliminating the proposed R4.2.

Response

Thank you for your comments: The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2: **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1.** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2.** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006. The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Comment	
The definition of a Balancing Authority is "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." During restoration, the local TO or TOP isolated island operations are not synchronized to the interconnection so they cannot support the	

interconnection frequency. Therefore, by definition, EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority should be removed. Balancing Authority functions will always reside with the designated Balancing Authority, even when operating as an isolated island. EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.
Response
Thank you for your comments. The EOP SDT added the BA due to the recommendations resulting from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. It is up to the TOP to define in their restoration plan how to interact with the BA v. designated BA. Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of BA is: “The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the BA does not relinquish any BA authority to the TOP. Revised language: “1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator’s criteria.”

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Comment	
In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement R1 the revision should read that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.	

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3. Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan.System modifications should be clearly defined. It should be limited to transmission and generation components. A definition of System modification should be added to the NERC Glossary. EOP-005-3 Parts 1.9 and 8.5 which refer to transferring of Balancing Authority authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.
Response
Thank you for your comments. The EOP SDT agrees that the language for Requirement R1 should be consistent across EOP-005-3 and EOP-006-3 and will revise EOP-006-3 to remove the word ‘maintain’. In EOP-005-3, ‘implement’ replaces Requirement R7; ‘maintain’ is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, ‘implement’ replaces Requirement 7; and ‘maintain’ is captured in Requirements R3 and R5. The EOP SDT discussed the suggestion to add energized islands to EOP-005-3, but believes the purpose of EOP-005-3 is to enable System Restoration from Blackstart Resources (purpose statement); and, therefore, decided it wouldn’t be appropriate to add this to EOP-005-3. The intent was that the TOP update its restoration plan when BES modifications need to be made that affect its ability to implement its restoration plan as describe in the Requirement R1 parts, not that the TOP has to make updates for minor revisions, such as element number changes or device changes that have no significance to the implementation of the plan. The EOP SDT revisions now provide clarity and separated “planned” and "unplanned” in Requirement R4 Parts 4.1 and 4.2. In Requirement 4 Part 4.2, the EOP SDT also added “subject to the RC approval requirements per EOP-006” to align the timing requirements of the RC approval.

In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the BA does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria." The EOP SDT discussed that 1.9 is needed to be incorporated into the TOP's Plan. Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the* Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Comment	
Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R3 and R8 is unnecessary, does not improve the standard, and is not consistent with numerous other standards that currently contain "Annual" requirements.	
Response	
The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Comment	

The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.	
Response	
In EOP-005-3, 'implement' replaces Requirement R7: "Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected TOP shall implement its restoration plan…"	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Comment	
Although generally supportive of the revisions made by the drafting team, the NSRF has concerns with the following requirements. 1.) **R1** - In consideration that developing and implementing a restoration plan represents two separate actions required by TOPs, we recommend the following change to R1 in order to clarify when the restoration plan is intended to be implemented. "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas…" 2. R8.5 needs to reworded. We understand the intent, which we agree with. Recommend from "Transition to Balancing Authority for Area Control Error and Automatic Generation Control" to "Transition back to Balancing Authority control for Area Control Error and Automatic Generation Control". This clearly states that a hand-off of responsibilities is warrented at the end of system restoration. 3.) We recommend retaining the current R1 language "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission	

Operator's System." We are concerned that deletion of the qualifying clause at the end of R1 will require an expansion of scope for all current Blackstart restoration plans.

Without the qualifying language, Transmission Operators are required to have a restoration plan for restoring the TOP's System, with Blackstart Resources required to restore the "shutdown area to service" without any qualification or limit to the "shutdown area" short of the TOP's entire BES "System."

In the worst case scenario when there is a total black out of the system the plan would have to be quite large. It would be difficult to cover all the variables and conditions that could likely be encountered. Maintenance of such a plan would be very difficult leading to compliance issues.

Possible alternative language: "The restoration plan shall allow for restoring the Transmission Operator's System following a disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to start generation for the restoration of the shutdown area to service."

4.) The replacement of "annual" with "at least once each 15 calendar months" in R3 & R8 introduces additional unnecessary administrative tracking requirements, restricting entities to submission or training, respectively, within a moving 4-month compliance window vs. the current flexibility of the entire calendar year. Demonstrating compliance would now require comparison with the previous completion date vs. showing annual accomplishment.

What is the justification for this complication? Preventing a possible interval of up to 23 months? What is the reliability risk of a 23-month interval vs. a 15-month interval? Such an occurrence would be self-correcting under the current annual requirement. If R3/8 were accomplished in Jan. 2018, and not again until Dec. 2019, the next occurrence would be required in Dec. 2020, no more than 12 months later, and earlier than the proposed new requirement of 15 months.

5. R4 – With Transmission Operators required to submit their updated restoration plan to the RC "no less than 30 calendar days prior to…planned System modifications", we are concerned the new timeframe may require TOPs to maintain two versions of their restoration plan in the control room due to confusion in terms of which restoration plan is considered valid while awaiting energization of a planned System modification.

As an example, a System modification impacting the restoration plan is scheduled to occur on September 1st so a TOP submits an updated plan to their RC on July 29th. The RC reviews and approves the plan on August 19th. To comply with EOP-005 R2 and R5 which require the TOP to provide the plan to System Operators and identified entities "prior to the effective date", the TOP distributes the newly approved plan on August 24th. Since the System modification is still over a week away from energization, which RC-approved restoration plan is considered valid?

6. R4 – Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications, …..

By inserting the previously included word "permanent" it is clear that the intent is for those permanent modifications that affect the restoration plan and not those temporary modifications that may come about due to temporary reconfiguration of the system such as may occur due to storm damage, etc.

Response

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented** to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

To address industry comments, the EOP SDT will be retaining the language in Requirement R1 from EOP-005-2 that states: "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System."

The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	No
Comment	

R1: Recommend retaining "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." Helps to provide guidance for an end point to the plan.

R8. Deletion of Requirement 8 is not advised. The Reliability Coordinator must play a defined role when establishing ties. It's the RC's role to ensure each Transmission Operator's System is ready for the connection. R8.5 The Restoration Plan is not intended to go to the extent of having ACE nor AGC available. If this is required significant addition to the Restoration Plans is foreseen as not enough of the system is restored to the point where ACE and AGC will be viable. The generating units will not be in a range to be placed on AGC in the plans as written today. If training for ACE and AGC is required, then wouldn't the restoration plans need to support same? If 8.5 is retained, recommend this requirement be trained in conjunction with a Balancing Authority Operator. This may require expanding applicability of EOP-005 to BA?.
Response
To address industry comments, the EOP SDT will be retaining the language in Requirement R1 from EOP-005-2 that states: "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The RC plan in EOP-006, Requirement R1 is required to have criteria for re-establishing interconnections, and the TOP plan is required to follow the RC plan (EOP-005 R1.1). Requirement R8 is duplicative of Requirement R1, Part 1.3, which states: "Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator." Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Comment	

ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point: The SDT should add a conditional phrase to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: "Each Transmission Operator shall develop, maintain, and, in the event of a Disturbance, implement a restoration plan…"	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Response	
Requirement R1 does state: "The restoration plan shall allow for restoring the Transmission Operator's System **following a Disturbance** in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service…" The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."	
Andrew Gallo - Austin Energy - 6	
Answer	No
Comment	
Austin Energy (AE) requests the SDT provide additional clarity regarding the TOP's scope of responsibility similar to EOP-006 R1. AE offers this suggestion: R1. Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the BES shuts down and the use fo Blackstart Resources is required to restore the affected area to service. Each Tranmission Operator shall implement	

its restoration plan when necessary to restore the portion of the BES under its control and interconnect with neighboring areas. If the Transmission Operator cannot execute the restoration plan as expected, it shall use its restoration strategies to facilitate restoration.

AE requests the SDT clarify R4.2. As written currently, it may imply restoration plans must be updated prior to any outage including short-term maintenance outages. AE does not believe such an action is necessary. Other Transmission Operators and the Reliability Coordinator are notified of temporary outages through local outage-related requirements. Additionally, AE does not believe the requirement clearly defines when the plan must be updated.

AE makes the following suggestions:

R4. Each Transmission Operator shall update, and submit to its Reliability Coordinator for Approval, its restoration plan to reflect System modifications which change its ability to implement its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modification; and

4.2. No less than 30 calendar days prior to the date on which the Transmission Operator energizes a permanent System configuration change.

Response

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.3 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.4 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Tina Garvey - Austin Energy - 4	
Answer	No
Comment	

I support the comments of Andrew Gallo.
Response
Please see responses to Andrew Gallo.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No

Comment

Most training is conducted on a yearly basis, with certain training required every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required “once per calendar year.” That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

The revision to EOP-005 R8 adds the requirement R8.5 - “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” TVA agrees with the addition of this requirement and thinks required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control.”

Response

The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: “The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the* Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.		
Andrew Pusztai - American Transmission Company, LLC - 1		
Answer	No	
Comment		

Comment on R3 & R3.1: ATC recognizes that FERC previously approved the retirement of R3.1. However, we recommend that the R3 language be changed to not require annual submission of the entire plan if no material have occurred. Requiring submission and RC response for these instances provides, in ATC’s opinion, little value to reliability. The standard should permit notification to the RC that the plan has not changed from the previous submission. As such, we propose that R3 be modified to read:

Each Transmission Operator shall review its restoration plan *for any substantive change,* and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually agreed, predetermined schedule *or notify its Reliability Coordinator that no sustative change occurred requiring approval of a new version of the TOP restoration plan*.

Comment on R4: As the SDT notes, TOPs should not have to submit a revised restoration plan to the RC to account for temporary changes to the system. However, the proposed edits to the standard language do not provide this clarity because R4.2 pulls in all planned modifications to the system, such as temporary configurations for construction or maintenance, that are not in view under the current EOP-005-2 R4 language. The new language pulls in these types of situations since the actual implementation of the plan in an event may be affect by construction activities (e.g., lines temporarily tied together) such that a different line gets used for a restoration path covered by R1.5 (i.e. very specific switching paths have to be identified in the plan). Today’s R4 is better suited to the realities of temporary construction activities where the plan does not need to be submitted to the RC for review because the plan already conceives of the potential for paths to not be available (see EOP-005-2 R7) such that the TOP would then use its restoration strategies to accomplish the restoration task. The SDT changes do not improve reliability. Rather, they add administrative burden without reliability benefit.

R4 recommendation: language should read "reflect *permanent* System modifications" to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.1 recommendation: language should read "unplanned *permanent* System modifications" to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.2 recommendation: language should read "planned *permanent* System modifications" to avoid pulling in temporary configurations needed to support maintenance or construction.

Comment on new R8.5: The proposed language for R8.5 is too specific for the standard. ATC recommends that R8.5 just read, "Transition to Balancing Authority".

Response

Thank you for your comment but the EOP SDT will be retaining the language in Requirement R3 to ensure its restoration plan was reviewed and submitted.

For Requirement R4, Part 4.2 to pair together with EOP-006 Requirement R5, Part 5.1, the TOP couldn't submit planned changes less than 30 days in advance; to conform with the 30 days the RC has to review the Operating plan in EOP-006, Requirement R5, Part 5.1. There should only be one effective plan in place.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

> **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
>
> **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications.
>
> **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Comment	

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace "develop and implement" with "have". R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon 'permanent' System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Response

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. “The restoration plan <u>**shall be implemented to restore**</u> the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.”

In EOP-005-3, ‘implement’ replaces Requirement R7; ‘maintain’ is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, ‘implement’ replaces Requirement 7; and ‘maintain’ is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that “*have a restoration plan*,” is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language “develop and implement” is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

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R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

The EOP SDT revised the rationale box of Requirement R6 based on industry comments to provide clarity. It now reads, "Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added." The EOP SDT made no substantive changes to Requirement R6 from EOP-005-2, Requirement R6.

In the Data Retention section, 'monitoring activity' has been changed back to 'compliance audit' to address comments received by industry.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No

Comment
We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace "develop and implement" with "have". R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon 'permanent' System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for 'permanent' system modifications. As stated, they require updates to be made for 'any' system modification no matter how small or impactful. R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish. In the data retention section for R1, it is not clear what the change to 'monitoring activity' means. It previously clearly stated data must be kept since the last 'compliance audit'. 'Monitoring activity' is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.
Response
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Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No

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Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	SCANA-SCEG Survey Responses.pdf
Comment	
Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would	

receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed. The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”
Response
The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: “The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	No
Comment	
Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement.	

Response

Measure M2 is stating that you have a receipt verifying any changes to the roles and specific tasks in the restoration plan. It does not speak to the entities' process once received. Dated electronic receipts and registered mail receipts are provided examples of possible verification.

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	No

Comment

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

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RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Comment	
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Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No

Comment

Refer to #2 comments.

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO

Answer	No

Comment

In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.

Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan.

A definition of System modification should be added to the NERC Glossary. Or Instead of the expression “System Modifications” in R4, “BES modifications would be a better choice. The NERC Glossary definition of BES includes “Blackstart Resource” in its inclusion list. I3 – Blackstart Resources identified in the Transmission Operator’s restoration plan.
Response
The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. “The restoration plan <u>**shall be implemented to restore**</u> the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.” In EOP-005-3, ‘implement’ replaces Requirement R7; ‘maintain’ is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, ‘implement’ replaces Requirement 7; and ‘maintain’ is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that “*have a restoration plan*,” is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language “develop and implement” is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2: **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.	
Quintin Lee - Eversource Energy - 1	
Answer	No
Comment	
In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that "Each Transmission Owner shall develop and implement a restoration plan approved by its Reliability Coordinator." However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Owner "shall develop, maintain and implement" a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3. Instead of the expression 'System modifications" in R4, 'BES modifications would be a better choice. The NERC Glossary definition of BES includes 'Blackstart Resources' in its Inclusion list · I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.	
Response	

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall

approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Comment	
CenterPoint Energy appreciates the SDT's time and effort towards the improvement of the System Restoration from Blackstart Resources Standard and is generally amenable to the proposed revisions. CenterPoint Energy would like the SDT to consider the following changes to EOP-005-3. In R1, for consistency between the proposed EOP-005-3 and EOP-006-3 standards, CenterPoint Energy suggests the SDT align the proposed language in both R1s to be the same and use either, "develop and implement", or "develop, maintain, and implement". Also, we are concerened that removal of the validation clause, "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage" expands the scope of a restoration plan. We suggest the addition of language regarding the plan's intended function of restoring the interconnecton and recommend the following: "The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service." Without such additional language, a TOP could be expected to include in its retoration plan, steps to restore every Facility in its entire system. Furthermore, we support the retirement of R7, but believe that the language, "If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration" should be retained in the proposed R1. This language provides a TOP the flexibility to make adjustments to its restoration efforts based on Real-time System conditions and Facility availability regardless of contingency. Considering all of CenterPoint Energy's comments R1 would state: "Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. The restoration plan shall include:" In R4.2, to further clarify and to better align with the SDT's proposed changes in R2, we suggest the SDT replace, "No less than" with "At least" and also replace "implementation of" with "effective date of ". The requirement would then read, "R4.2. At least 30 calendar days prior to the Transmission Operator's effective date of the planned System modifications." CenterPoint Energy also believes that the proposed EOP-005-3 R8 (currently enforceable EOP-005-2 R10)	

along with its sub-requirements 8.1, 8.2, 8.3, 8.4, and 8.5 should be retired as they are inherent to the systematic approach to training processes. It is not that the requirements are duplicative, but rather that they are already incorporated in the training and periodicity of training that would be identified in a TOP's PER-005-2 analysis for company-specific reliability-related tasks. The criteria required to be included in the restoration plan outlined in R1.1 thru R1.9 further ensures that specific training content would be provided on system restoration and maps to the content being required in R8.1. R8.2, R8.3, R8.4, and R8.5. Retirement of R8 and its sub-requirements does not eliminate reliability-related task training on System Restoration from Black Start Resources. This rationale was applied in the recent revisions to PRC-001-1.2 (Project 2007-06.2) and industry approval of PER-006-1 to which training related requirements for the TOP were mapped out and retired. CenterPoint Energy urges the SDT to consider soliciting assistance and guidance from the PER-005 SDT and members from the training sector in the industry to assist in this matter.

Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

The EOP SDT held extensive discussions on Requirement R10. Requirement R10 is being retained in EOP-005, as it is specific training with high impact, low occurrence. The PER-005 standard entails more of training processes.

In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Comment

(1) R1 now includes "develop and implement" a restoration plan for the TOP. Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including two actions, having a plan and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has nine sub-parts,

which can now be reviewed under two filters – is it documented and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the nine sub-parts.

(2) We question the need for a change in R2 and R5 from "implementation date" to "effective date." They appear synonymous.

(3) We agree with the modification to R3 and R8 to remove the word "annually" and replace it with "at least once every 15 calendar months," as this aligns with several other NERC standards. We also agree with the removal of sub-part 3.1, as this was administrative in nature.

(4) Requirement R4 now requires the TOP to submit its restoration plan to the RC no more than 90 calendar days after identification of any unplanned system modification and no less than 30 calendar days prior to the TOP's implementation of planned system modifications. We question why the planned modifications were added to the requirement, as the TOP will be providing planned outages and other information to the RC already.

(5) Requirement R8 (formerly R10), added sub-part 8.5, which now includes the TOP to have training every 15 calendar months on the "transition to BA for ACE and AGC." We recommend modifying the phrase to "coordinate with the BA for restoration activities." The word "transition" could be misinterpreted that the TOP completely transfers their role to the BA in system restoration.

(6) Measure M10 (formerly M12), removed training records as proof of participation in restoration drills. Why was that type of evidence removed? It seems like the most straight-forward way to prove compliance with the requirement. Further, training records are still listed in M16 for GOP participation in restoration drills. This should be consistent throughout the standard.

Response

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The SDT interprets "effective date" to refer to a plan that is approved and ready for implementation. The "Implementation date" of any given plan pertains to any given use of a restoration plan by an entity.

The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall

approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements. Requirement 8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the [Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans](). Measure M10 was revised for consistency to the language of the requirement, which is a requirement for restoration drills, exercise, or simulations.	
Richard Vine - California ISO - 2	
Answer	No
Comment	
R1: For the purposes of managing internal controls, and clear internal controls ownership and tracking, consider keeping this requirement as Operations Planning horizon only and then do not remove R7 and R8. Plan development and administration is an Operations Planning function. Real Time is not responsible for development and maintenance of the plan. R4.2. Is revised to state: **4.1.4.2.** No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications. This revision takes away flexibility. Suggest that "No less than 30 calendar days prior to" be changed to "Up to 90 calendar days after implementation of planned System modifications". Planned implementation dates are often moving targets and can move earlier or later, due to construction and crew scheduling needs, and well outside of the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action.	
Response	
With the clarifications the team added to include "implement," therefore, Real-Time horizon was added.	

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	No
Document Name	FE 2015-08_EOP-005-3_IB_Comment_Form.docx
Comment	

Requirement R4: The proposed changes to R4 cause concern for FirstEnergy. The existing FERC approved requirement R4 requires notification by a Transmission Operator (TOP) to its Reliability Coordinator (RC) for a "permanent" system modification (planned or unplanned) "that would change the implementation of its restoration plan." The proposed revisions by the drafting team, while well intended, shifts the emphasis to changes that affect "ability to implement" the TOP restoration plan regardless of whether or not the system modification (planned or unplanned) is temporary or permanent. This change would cause numerous re-writes of restoration plans by TOPs and approval reviews by RCs resulting from planned maintenance outages of BES transmission facilities (lines, transformers, generators, etc.), many of which are short duration outages. FirstEnergy believes it is important to retain the "permanent" modification aspect of the existing FERC approved requirement. The proposed change results in an overly burdensome requirement without significant improvement to BES reliability.

FirstEnergy does support the intended 90-day notification for unplanned changes and the minimum 30-day lead-time from the effective date of planned changes.

FirstEnergy proposes the requirement be written as follows:

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the implementation of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

A red-line version of our proposed changes is provide in the attached version of FE comments.

Response

Thank you for your comments. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	

We suggest the following edit to R1 for clarity:

"R1 Each Transmission Operator shall **develop** a restoration plan approved by its Reliability Coordinator. The **implemented** restoration plan shall allow…"

We believe this better aligns with the intent and doesn't create confusion that potentially an entity must have experienced a blackout in order to fully comply (a need to 'implement') with R1.

In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon 'permanent' System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

We have a concern that R6 in combination with the changes to R1 may seem to create a conflict or confusion. The changes to R1 seem to indicate the plan now covers restoration all the way up until balancing is turned over to the BA. That would seem to describe the ‘intended function’ of the plan as stated in R6. The sub-requirements in R6 seem to indicate simulation and analysis only needs to be done on energizing the Blackstart resource and connect initial loads. Perhaps R1.8 could be rephrased to better clarify the ‘intended function’ of the plan in order to better align with R6. We do not believe the intent is for dynamic simulation to be done for the entire restoration scenario all the way up to handoff to the BA in R1.9. Perhaps R6 could be rephrased such that it states:

R6 Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes **initial restoration**.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. “The restoration plan **shall be implemented to restore** the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.”

In EOP-005-3, ‘implement’ replaces Requirement R7; ‘maintain’ is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, ‘implement’ replaces Requirement 7; and ‘maintain’ is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that “*have a restoration plan*,” is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language “develop and implement” is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP’s ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

The EOP SDT revised the rationale box of Requirement R6 based on industry comments to provide clarity. It now reads, “Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.” The EOP SDT made no substantive changes to Requirement R6 from EOP-005-2, Requirement R6.

In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: “1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator’s criteria.”

In the Data Retention section, 'monitoring activity' has been changed back to 'compliance audit' to address comments received by industry.	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	No
Comment	

Requirement R1: In the first sentence of Requirement R1, the proposed revision is to change the requirement that each Transmission Operator "shall have" a restoration plan approved by its Reliability Coordinator to state that each Transmission Operator "shall develop and implement" a restoration plan approved by its Reliability Coordinator. However, in order to be consistent with the language that is already been used in other requirements (see, e.g., the proposed revision in EOP-006-3, Requirement R1), the revision should state that each Transmission Operator "shall develop, maintain and implement" a restoration plan approved by its Reliability Coordinator. Accordingly, the ISO/RTO Council Standards Review Committee (SRC) suggests that the word "maintain" be added to the proposed revision. [CAISO does not support this paragraph.]

Requirement R4: The proposed revision in Requirement R4 requires the Transmission Operator to update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that would change the ability to implement its restoration plan. The requirement, however, should be clarified to indicate that the type of System monifications that would require an update to the restoration plan are only permanent System modifications that would change the Transmission Operator's ability to implement its restoration plan. Limiting the requirement to reflect permanent modifications is consistent with the Rationale for Requirement R4, which states that the intent of the revisions is to require the Transmission Operator to update its restoration plan when major modifications need to be made, and not to require the Transmission Operator to make updates for minor revisions. Without the qualifying word "permanent," the proposed revision could be read as requiring updates to the restoration plan for all System modifications that would change the Transmission Operator's ability to implement the restoration plan, even if those System modifications are not permanent (such as for planned or unplanned outages). In the event that temporary System modifications or other unforeseen system conditions prevent the Transmission Operator from implementing the restoration plan as expected, system restoration would be facilitated by implementing the restoration strategies that Requirement R1 requires to be included in the restoration plan. System modifications that would change the Transmission Operator's ability to implement the restoration plan that are not permanent are not "major." Requiring that the restoration plan be updated for such non-permanent System modifications would translate into multiple, unnecessary updates to the restoration plan. For this reason, to make the requirement even clearer, the SRC suggests that the word "permanent" (which is included in the currently enforceable version of this Requirement) be added to the proposed revision. Note that, for consistency, the word “permanent” should also be added in all the Violation Severity Levels for Requirement R4.

In addition, we suggest R 4.2. which currently states: “4.2. No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications” should be modified to state ”4.2. Up to 90 calendar days after implementation of planned System modifications.

Planned implementation dates are often moving targets due to construction and crew scheduling needs. It is well outside the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action. [NYISO does not support this comment.]

Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. “The restoration plan <u>shall be implemented to restore</u> the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.”

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP’s ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and

submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements. In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Comment	
The stricken phrase "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." should be retained. Since R1 is specifying that the TOP shall have an SRP to restore its system, it is imperative that the TOP has a defined state at which point it knows that it has successfully achieved the requirement. The stricken language provided that. Although R1.8 contains similar language, it is in the context of information that the TOP must include in its SRP, as opposed to defining success in achieving system restoration. Compliance with R1.8 does not inform the TOP, or an auditor, that if the TOP completes the processes contained in the subrequirement, that it has successfully achieved system restoration.	
Likes 1	New York State Reliability Council, 10, ADAMSON ALAN
Response	

Thank you for your comments. To address industry comments, the EOP SDT will be retaining the language in Requirement R1 from EOP-005-2 that states: "to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System."	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	No
Comment	
Putting the word "implement" in EOP-005-3, R1: "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator", is confusing. What is meant by "implement"? Public Utility District of Chelan County (CHPD) understands "implement" to mean to put the Restoration Plan into effect. The Restoration Plan is not put into effect until there is a real-time event. CHPD would prefer the sentence to read: Each Transmission Operator shall develop a restoration plan and have it approved by its Reliability Coordinator.	
Response	
The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **<u>shall be implemented to restore</u>** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service." In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The SDT interprets "effective date" to refer to a plan that is approved and ready for implementation. The "Implementation date" of any given plan pertains to any given use of a restoration plan by an entity.	

Michael Jones - National Grid USA - 1	
Answer	No

Comment

The proposed requirement R4.2 requires TOPs to submit revised System Restoration Plans “No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications.” This is not practical or advisable as it would result in the need for TOP’s to submit revised Restoration Procedures to the RC which do not align with actual system configuration during the (at least) 30 day period. Restoration plans are typically “approved” procedures that reflect current configuration and have a review and approval process internal to the TOP. Approval of revisions are closely coordinated with actual implementation of system modifications to ensure that proper configuration control is maintained between procedures and the system. Having to submit a revised (and approved) procedure at least 30 days in advance of field implementation would result in procedures having to be approved and sent to an RC that do not align with actual system configuration for “extended” periods (at least 30 days). Even if an effective date is used in a TOP’s procedural control process, having to assign such a date in excess of 30 days prior, would likely result in a significantly increased administrative burden due to the higher potential for date changes to occur between procedure approval and final implementation of a modification in the field. Field implementation of system modifications are subject to a degree of uncertainty due to a variety of factors (testing results, weather, system operational needs, etc). The greater the period of time between procedure revision approval and placement of a system modification in-service, increases the potential for subsequent procedure date changes being required and also raises the potential for non-alignment between Restoration Procedures and field configuration. Even if Draft Restoration Procedures are submitted to an RC, it is not clear that this would be satisfactory from a compliance standpoint for the TOP or the RC as proposed EOP-006-3 R5 requires the RC to approve a submitted TOP plan within 30 days of its receipt.

It is suggested that the proposed R4.2 be changed to delete “No less than 30 calendar days” and maintain the existing requirement to submit revised, planned, Restoration plans prior to their implementation.

Response

Thank you for your comments. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	No
Comment	
Portland General Electric Company (PGE) appreciates the efforts of the STD and being able to provide comments throughout this project. In the measure for R1 (M1) the term Disturbance is used, "…when a Disturance occurred…" Since not all Disturbances are Blackstart events, PGE suggests changing Disturbance to applicable event.	
Response	
Thank you for your comment. EOP-005-3 is a Blackstart Resource standard.	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	No
Comment	

Compliance (Sec C.1)

We have concerns replacing “compliance audit” with “monitoring activity.” The proposed term, “monitoring activity,” is vague, ambiguous, and muddies the interpretation of the retention period. We can only speculate as to the reason for the change and, so, are unable to offer a suggestion to address our concern.

R2, R5, and R8

We are supportive of replacing “implementation date” with “effective date” and believe it provides added clarity.

We are supportive of replacing “annually” with “15 months” and believe it provides added clarity.

Response

Thank you for your comments. In the Data Retention section, ‘monitoring activity’ has been changed back to ‘compliance audit’ to address comments received by industry.

The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Comment	

For R3, Peak already has all the TOPs scheduled on an annual submittal process. Peak is concerned that TOPs will want to switch to a 15-month submittal process, which will be more difficult to track. Every approval will require an agreement on the next submittal scheduled rather than maintaining a known, 12-month schedule. For R10, Can R16 be combined with R10? There are other requirements that combine various entities so not sure why participating in the RC's restoration plan would need to be separate requirements for TOPs and GOPs.	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards* Requirements also provides guidance on defining "annual". The EOP SDT discussed your comment and made no revisions to Requirement R10 nor to Requirement R16. The separation of the Functional Entities provides clarity to the standard.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Comment	
The Purpose statement becomes an absolute positive by replacing "assure" with "ensure" therefore the restoration plan must reestablish reliability. System Operators need the flexibility to deviate from the plan in order to restore the system to precontingent operations.	
Response	
Thank you for your comments. The EOP SDT discussed this issue and decided, for clarity, as well as consistency throughout the standards, to revise the Purpose of the standard from "assure" to "ensure."	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	No

Comment
In R1 we recommend that the first sentence be changed from "Each Transmission Operator shall develop and implement a restoration plan approved by its Relability Coordinator."to "Each Transmission Operator shall develop and publish a restoration plan approved by its Relability Coordinator that will be implemented folwing a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down." The reason for this recommendation is to clarify the intention of the proposed change. In R1, we disagree with the change after the words "… is required to restore …". Depending upon the cause of the Disturbance (for example physical damage) that requires system Restoration from Blackstart Resources, it may not be feasible to restore the entire shutdown area of service even though the BES has been restored. We recommend leaving the original wording in place. In R4.2, we disagree with the wording "No less than 30 calendar days prior to …" in the first sentence. We recommend changing to "Up to 90 calendar days after implementation of planned System modifications". The reason for this recommendation is that planned implementation dates are often moving targets due to factors such as construction or equipment delays; crew scheduling needs; or other factors outside the direct control of the entity.
Response
The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan <u>**shall be implemented to restore**</u> the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service." In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Comment	

We support NPCC's comments.

In addition, we have the following comments.

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3. However, we recommend inclusion rather than removal. Indeed, EOP-005 ‘s scope could be expanded to “System Restoration” regardless of whether Blackstart Resources are required or not. A TOP may have a major shutdown or be islanded and restore its area by synchronizing with an adjacent area. Such a TOP should nevertheless have a Restoration Plan, perform simulations as well as training. Such a change in scope would only require changes to the title and the purpose.

We note that R16 applies to Generator Operators, not Generator Operators identified in the Transmission Operators restoration plan, as was the case in EOP-005-2 R18. Most requirements in EOP-005-3 that apply to GOPs apply to GOPs with Blackstart Resources and these are identified in the TOP’s Plan. Modifying section 4.1.2. to apply only to GOP with Blackstart Resources would be consistent with EOP-006-3 R8 part 8.1 which specifies “each Generator Operator identified in the Transmission Operators’ restoration plans”. We recognize however that R16 is consistent with EOP-006-3 R8 in a general sense and also recall that in the development of EOP-005-2, comments on the same point were submitted and rejected by the drafting team at that time. If this project's drafting team rejects this comment again, **we request the addition of a rationale to clarify the purpose of this broader scope.** We note that the Régie de l'énergie here in Québec ordered a reduction of scope of R16 to the GOPs identified in the TOP plan, based on the lack of justification provided during the development of EOP-005-2 for the broader scope of R18 (now R16 in EOP-005-3).

R1: Suggest adding a rationale to explain change of scope. Does the removal of “the choice of the next Load to be restored is not driven by the need to control frequency or voltage” imply that the scope of the TOP’s restoration plan is now until all the BES is restored?

We understand that the EOP-005-3 Parts 1.9 and 8.5 that refer to transferring of Balancing Authority authority come from a FERC-NERC report. However, we believe that Balancing Authority functions always reside with the Balancing Authority. The requirement could be rephrased as a more general requirement to 'coordinate' the restoration with the appropriate BA, per RC criteria.

Response

Thank you for your comments. The EOP SDT discussed the suggestion to add energized islands to EOP-005-3, but believes the purpose of EOP-005-3 is to enable System Restoration from Blackstart Resources (purpose statement); and, therefore, decided it wouldn’t be appropriate to add this to EOP-005-3.

Requirement R1 does state: "The restoration plan shall allow for restoring the Transmission Operator's System **following a Disturbance** in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service…" The EOP SDT added the BA due to the recommendations resulting from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. It is up to the Transmission Operator to define in their restoration plan how to interact with the BA v. designated BA. In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria." Requirement R16: This requirement was developed in coordination with the RC requirements (EOP-006, Requirement 8); therefore, based on the RC's scenario, any Generation Operator (GOP) identified will need to participate in the RC's Restoration drill.	
Wes Wingen - Black Hills Corporation - 1	
Answer	No
Document Name	Comments on EOP 5.docx
Comment	

EOP-005-3 R1:

Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shuts down~~ shutdown area to service. ~~To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.~~

Comment:

a) The wording *"develop and implement"* has led to some confusion among entities who only see the requirement (the first sentence) and do not take into account the rest of the requirement and also the measurement of compliance associated with the requirement.

M1 states: Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its

Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with R1

"To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." As *"to restore the ~~shuts down~~ shutdown area to service,"* could have broader implication for restoration of every part of the system down to what level of distribution?

EOP-005-3 R9:

Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as ***performing unique tasks associated with the Transmission Operator's restoration plan that are outside their normal tasks.***

Comment:

a) Recommend improved language adding clarity to the term "unique tasks" – what does this mean? Does this mean restoring islands, synchroscopes, and restoring station power? Or?

Response

The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The EOP SDT has added a rationale box for Requirement R9 to address "unique tasks." The rationale box says, "The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider."

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	No
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Comment	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Comment	

For the sake of consistency I recommend considering on page 9 of 24 second line of M13 replacing the text "e-mail with" with "dated electronic". Similarly on page 10 of 24 third line of M14 the text "e-mail with" should be replaced with "dated electronic".	
Response	
Thank you for your comment. The EOP SDT has updated Measure M13, revising from 'e-mails' to 'dated electronic receipts.'	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period. Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification. Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.	
Response	
The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:	

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

The EOP SDT added the Balancing Authority due to the recommendations resulting from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. It is up to the Transmission Operator to define in their restoration plan how to interact with the Balancing Authority v. designated Balancing Authority.

Thank you for your comment. In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Comment	

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Response

The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements. The EOP SDT added the Balancing Authority due to the recommendations resulting from the Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. It is up to the Transmission Operator to define in their restoration plan how to interact with the Balancing Authority v. designated Balancing Authority. Thank you for your comment. In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."		
Jamie Monette - Allete - Minnesota Power, Inc. - 1		
Answer	Yes	
Comment		
Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:		

Response	
The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service." In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:{C}[JM(1] {C}[JM(1]Bob H. addition	
Response	
The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."	

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1. In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
FMPA generally agrees with the revisions proposed for EOP-005, but does have some comments. R1 can still be interpreted that a TOP who would be restored via a tie line with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here? The phrasing of R4 needs work. FMPA recommends adding commas and removing the word "of". "Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:" R5 should use the defined term Control Center, rather than control room.	
Response	
Thank you for your comments. If there is a disturbance in which one or more areas of the BES shuts down and the use of Blackstart resources is required, a restoration plan is still required. R1. "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator." And the purpose statement of EOP-005-3 states, "**Purpose:** Ensure plans, Facilities,	

and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Requirement R1, Part 1.1 states, "Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection." The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2: **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006. The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements. The EOP SDT discussed your comment regarding Control Center v. control room; however, the copy of the restoration plan needs to reside within the control room.	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes

Comment
In spirit APS is supportive of the SDT's direction. That said, APS offers the following suggested changes with respect to the proposed wording of the standard. APS suggests the following revised wording to further clarify the language in the proposed EOP-005 standard. **R4.** Each Transmission Operator shall update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that necessitate a change in how the Transmission Operator implements its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1.** No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications; and **4.2.** No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications. **M5**. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available to its System Operators in its primary and backup control rooms in electronic or hardcopy format prior to its effective date in accordance with Requirement R5. *In addition, APS requests the SDT clarify the text for requirement R8.5 to align the requirement language with the text in the Rationale box for R8:* **R8.5** Coordination needed to transfer the following functions back to the Balancing Authority: Area Control Error and Automatic Generation Control.
Response
Thank you for your comments. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2: **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

Ken Simmons - Gainesville Regional Utilities - 1,3,5

Answer	Yes

Comment

GRU generally agrees with the revisions proposed for EOP-005, but does have some comments.

R1 can still be interpreted that a TOP who would be restored via a tieline with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here?

The phrasing of R4 needs work. GRU recommends adding commas and removing the word "of".

"Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:"

R5 should use the defined term Control Center, rather than control room.

Response

Thank you for your comments. The intent of R1 has not changed. If there is a disturbance in which one or more areas of the BES shuts down and the use of Blackstart resources is required, a restoration plan is still required. R1. "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator." And the purpose statement of EOP-005-3 states, "**Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Requirement R1, Part 1.1 states, "Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection."

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes

Comment

1. R4 Rationale: In the second paragraph the SDT may want to consider removing the word 'major' when describing System modifications as the requirement does not have this limitation, but instead deals with any System modifications that change the ability to implement the restoration plan. The use of the term 'minor' when describing revisions provides the appropriate context. Dominion also suggests the SDT could add examples into the Rationale to clarify the types of System modifications they are referring to.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance; The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Response

Thank you for your comments.
The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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The template formatting has been updated.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	

Hydro One Networks Inc. would like to inquire from the drafting team on what an auditor would be required to view as evidence for measure M1 in the case that a Disturbance has not occurred over a given period in time?

Response

Thank you for your comment. Consistent with the revision to Requirement R1, the EOP SDT intends to underscore the need for Transmission Operators to utilize their restoration plans. The evidence identified in this Measure is exemplary and not exclusive and its inclusion is consistent with the Standards Process Manual's intended purpose of a Measure. The SPM states that a Measures "[p]rovides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirements."	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Comment	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Comment	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Comment	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	
Response	

Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Comment	

R1: Duke Energy recommends that the drafting team consider the following language revision to R1.

"Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator."

We think that the addition of the term "maintain" is appropriate and would promote consistency with other EOP standards.

Also, we request clarification from the drafting team about the potential for an instance of double jeoparday. If an addition to the term "maintain" to R1 is deemed appropriate by the drafting team, does that open up entities to the possibility of violating two requirements if the restoration plan is not maintained. See Duke proposed R1 language, and SDT proposed language of R4. Does the failure to maintain a restoration plan create double jeopardy with R1 and R4?

R4: Duke Energy recommends the drafting team consider revising the proposed R4 to read as follows:

"Each Transmission Operator shall update and submit to its Reliabilty Coordinator for approval of its restoration plan to reflect system modifications, that would inhibit its ability to implement its restoration plan, as follows:"

We feel that replacing the word "change" with "inhibit" or "adversely affect/negatively impact" is more accurate representation of what is needed in this requirement. Moreover, any planned or unplanned system modification could "change" the way an entity executes its restoration plan, but an entity would still be able to execute said plan via multiple paths. We feel that the spirit of this requirement should be geared more towards system modifications that prevent an entity from executing its restoration plan altogether.

R8: Duke Energy recommends that the drafting team consider maintaing the use of the annual system restoration training, rather than using *"at least once each 15 calendar months".* We have a couple of concerns with the use of once each 15 calendar months. First, we are not aware that NERC has defined the term(s) calendar months. Some ambiguity may exist amongs industry stakeholders about what constitutes a calendar month. The use of the term "annual" is commonly used throughout the industry, and NERC has issued a Compliance Application Notice on the use of the term, and there seems to be more guidance on the tracking of annual timeframes.

R8.5: Duke Energy requests further clarification from the drafting team on how this requirement should apply to vertically integrated BA(s) and TOP(s) that are in the same control room. Also, with regards to the transition of ACE and AGC to the BA, where in the standard is it referenced when/if control was ever passed to the RC? Does this not go beyond what is outlined in R1.9? The language as written implies that a TOP was at one time in control of ACE or AGC. Not all entities may pass control over to the TOP, especially those entities that are vertically integrated, wherein the BA and TOP are in the same control room. We understand that this addition was a result of the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans, however, we don't see this change as representative of the practices of the entire industry, and can't agree with this addition based on the complication it may provide to vertically integrated companies.

Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

In this industry it is widely understood that “*have a restoration plan*,” is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language “develop and implement” is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R5. **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP’s ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	

Comment

PJM is concerned with the removal of the words in R1. In the proposed Standard, it is not clear when the use of the Restoration Plan should end. Adding the word "implement" to R1 and other requirements puts two actions in one requirement which makes the VSLs much more complicated. PJM has serious concerns with a misinterpretation of R6. The misinterpretation is that the entire Restoration Plan should be simulated using dynamics. That was not the intent of the SDT. Suggest adding "a combination of" before "steady state and dynamics simulations". PJM would also recommend the addition of language clarifying that Dynamic simulation is only required from Blackstart unit to cranked unit (along the cranking path), and not the entire restoration plan. Also, PJM finds the "30 day prior to implementation" wording in R4.2 is troubling. This Requirement could potentially lead to artificial delays in energizing new equipment just to meet the 30 day requirement. PJM considers the wording in the current standard ("prior to a permanent planned modification") sufficient, rather than introducing the 30 day prior requirement.

Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan **shall be implemented to restore** the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R6. **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	

Comment
Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a TOP's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program. Texas RE is concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval. Texas RE is concerned about the proposed changes to EOP-005-2, Requirement R4. In particular, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification "that would change the ability to implement" the restoration plan. Although Texas RE does not necessarily object to the SDT's stated intent to require updates solely for material changes, the requirement to update a plan should not hinge upon the entity's perception of its corresponding "ability" to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding material modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness. If the SDT wishes to capture a materiality threshold for required updates and submissions, however, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update "to reflect system modifications that would materially change the implementation of its restoration plan."
Response

Thank you for your comments. The EOP SDT added language to provide clarity, and also pertains to the deletion of the implementation plan in retirement of Requirement R7. "The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service."

In EOP-005-3, 'implement' replaces Requirement R7; 'maintain' is captured in Requirements R2, R3, R4 and R6, so it would create a redundancy to be written within the language of Requirement R1. In EOP-006-3, 'implement' replaces Requirement 7; and 'maintain' is captured in Requirements R3 and R5. This is consistent with other standards, such as EOP-011-1 and EOP-010-1.

In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT in adding the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized.

The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:

R7. R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6

Answer	No

Comment

Requirement 7 as it appears in EOP-005-2 is a better way to address the “implement” intent of EOP-005-3 R1.

Response

Thank you for your comment. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.

Gregory Campoli - New York Independent System Operator - 2

Answer	No

Comment

R7 should be retained. It is imperative that a TOP have a fallback position in the event its SRP cannot be implemented as intended. R7 specifies to the TOP that the fall back position is to utilize its strategy. For example, a TOP’s SRP might have detailed steps to restore a certain generating unit, perhaps by specifying a particular switching scheme. If the facilities to execute that scheme are not available, the TOP should still recognize the need to restore that unit, and proceed in any manner available to do so. The strategy is to restore the unit regardless of the tactics used to accomplish that. R1.1 does obligate a TOP to include it strategies in its SRP, but it does not obligate it to operate to those strategies if need be. Further, the strategies in a TOP SRP are at a more detailed level than the strategy of the RC plan in EOP-006. An RC’s plan is, in effect, it’s strategy, and is at a much higher and more general level than the TOP plan. Therefore, there is no inconsistency with retaining R7 in EOP-005 and removing it from EOP-006.

R8 should be retired.

Response	
Thank you for your comments.	
Richard Vine - California ISO - 2	
Answer	No
Comment	
Please see comment in response to Q1 above.	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
It is the responsibility of the TOP to notify the RC before resynchronization with neighbors, Southern believes that without specifically being addressed in a standard that some TOPs may not be compeled to consult with the RC before restoring tie-lines creates a potential reliability gap. Comment for EOP-005-3 R4.1: No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications that would affect implementing the restoration plan. Comment for EOP-005-3 R4.2: No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications that would affect implementing the restoration plan.	
Response	
Thank you for your comments. The following revisions were made to Requirement 4 and Requirement 4, Parts 4.1 and 4.2:	

R8. **R4.** Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No

Comment

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement. Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.	
Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement. Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.	
Response	

Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Response	
Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No

Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.	
Response	
Thank you for your comments. "Implement" replaces the requirements of R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.	
Tina Garvey - Austin Energy - 4	
Answer	No
Comment	
I support the comments of Andrew Gallo.	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	No
Comment	
Unless the changes AE recommends above are implemented, R7 should not be deleted in its entirety. (See AE's response to Question 1, above) Because of the vagaries of a blackstart situation, AE believes the Standard should allow the Transmission Operator to solve issues which may not be addressed in the restoration plan. AE believes it is not possible to plan for every possible contingency and, therefore, Transmission Operators need a degree of freedom to address deviations from expectations. Therefore, AE requests the sentence "If the	

restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration" remain unless included in R1 as suggested above.		
Response		
Thank you for your comments. "Implement" replaces the requirements of R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.		
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF		
Answer	No	
Comment		
R7: . Implementation documentation should remain covered under the current Requirement 7. Focus should be on developing a restoration plan in Requirement 1 and Measurement 1 should not be confused with implementation documentation. Revise the existing R7 requirement for implementation and measures for implementation as needed. R8. Recommend retaining or at least retaining "in accordance with the established procedures of the Reliability Coordinator". Much work has been done in this venue to provide needed guidance, and see this as an efficient way to accomplish. The Reliability Coordinator must play a defined role when establishing ties. It's the RC's role to ensure each Transmission Operator's System is ready for the connection.		
Response		
Thank you for your comments. "Implement" replaces the requirements of R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.		
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance		
Answer	No	
Comment		
Response		

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	
We support NPCC's comments.	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Comment	
Reword R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control” needs to clearly state that a hand off of responsibilities are necessary at the end of system restoration.	
Response	
Thank you for your comments. Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: “The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.”	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Comment	
We are supportive of the retirements proposed in EOP-005-3 of R7 and R8.	

Response	
Thank you for your support.	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Comment	
Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall “implement” a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 can, and should, be retired. [CAISO and NYISO do not support this comment]	
Response	
Thank you for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
We understand the rationale behind the changes.	
Response	
Thank you for your support.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Comment	
We agree with the proposed retirements of R7 and R8.	
Response	

Thank you for your support.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Comment	
See comment to Question 1 proposing to retain the use of the language, “If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration”.	
Response	
Thank you for your comments. Please see responses in Question 1.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
No comments	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Comment	
What is the SDT’s thought process in removing the need for the Transmission Operator to obtain authorization of the Reliability Coordinator prior to resynchronizing its area with that of a neighboring Transmission Operator’s area under requirement R8?	
Response	

Thank you for your comments. “Implement” replaces the requirements of R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes

Comment

Assuming that Requirement R1 is being revised to state that the Transmission Owner shall “implement” a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 should be retired.

Response

Thank you for your support.

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes

Comment

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall).   BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Response

Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining “annual”.

Thank you for your comment. In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period. Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining "annual". In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria." Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans	

ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
I agree with the changes however, training requred by R8.5 makes no sense if a TOP does not manage Area Control Error and/or Automatic Generation Control. My utility is a small TOP and has neither ACE management or AGC management. Training in the transition of this functionality to the BA is unnecessary since the BA provides this funcionality as part of its normal operations.	
Response	
Thank you for your comments. Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Comment	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Comment	

Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Comment	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Comment	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Comment	

Response
Johnny Anderson - IDACORP - Idaho Power Company - 1

Answer	Yes

Comment
Response
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes

Comment
Response
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6

Answer	Yes

Comment
Response
Andrew Pusztai - American Transmission Company, LLC - 1

Answer	Yes

Comment	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Comment	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Comment	
Response	

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Comment	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Comment	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Comment	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Comment	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes

Comment	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Comment	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Comment	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Comment	
No. Texas RE does not necessarily object to the SDT's proposal to retire Requirements R7 and R8 from the EOP-005-3 Standard. However, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-	

3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration." As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs "resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator." Although it is perhaps possible to read R1.1's mandate that the restoration plan include "[s]trategies for system restoration that are coordinated with the [RC's] high level strategy for restoring the interconnection" as encompassing this requirement, it is not clear that resynchronization is included within either "system restoration strategies" or the RC's "high level strategy." Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator.

Texas Re noticed draft EOP-005-3 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and Enforcement Program. There is no section for Reset Time Frame, Compliance Monitoring and Enforcement Processes, or Additional Compliance Information.

Response

Thank you for your comments. In response to industry comments, the EOP SDT has revised the language in Requirement R1, Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria." Requirement 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board-approved definition of Balancing Authority is: "The Responsible Entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Comment	
It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.	
Response	
Thank you for your comment. In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Comment	
It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.	
Response	
Thank you for your comment. In response to industry comments, the EOP SDT has revised the language in Requirement R1 Part 1.9, since the Balancing Authority does not relinquish any BA authority to the TOP. Revised language: "1.9 Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."	

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No

Comment

The word "neighboring" should be replaced with the word "electrically adjacent" in all instances in the standard (including the Violation Severity Levels). "Electrically adjacent" lends more clarity to the intent of the requirements than "neighboring."

It is suggested that the below changes be made to Part 4.1 so that it reads:

"If a Reliability Coordinator finds conflicts between its restoration plan and the restoration plan of an electrically adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar-days of written notification of the identified conflicts from the Reliability Coordinator to the adjacent Reliability Coordinator."

The additional revisions clarify that both the initiating Reliability Coordinator, and the electrically adjacent Reliability Coordinator have to resolve any conflicts. The timing for resolution of the conflicts will also be made clear.

Response

Thank you for your comments. The EOP SDT determined that the addition of "adjacent" in R1.2 is unnecessary and is captured by the use of "neighboring" in Requirement R1. "Neighboring" gives the RC the latitude to define which applicable entities are to be included in its restoration plan.

The EOP SDT has addressed your concern in Requirement 4 and Requirement 4, Part 4.1 as follows:
R4. Each Reliability Coordinator shall review its adjacent Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt.

4.1 If a Reliability Coordinator finds conflicts between its restoration plans and any adjacent Reliability Coordinator's restoration plan, the conflicts shall be resolved within 30 calendar days of written notification.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Comment	
Consider revising R3 to allow "Annual" review to be consistent with other NERC standards. The verbiage change from "Annual" to "at least every 15 months" in R7 is unnecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Comment	
The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.	
Response	
Thank you for your comment. The EOP SDT removed "maintain" from R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	

Answer	No
Comment	

ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point:

Similar to the comment for Question #1, we ask that a conditional phrase be added to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: “Each Reliability Coordinator shall develop, maintain, and, in the event of a Disturbance, implement a Reliability Coordinator Area restoration plan.”

If the SDT intends there to be a difference in meanings of the words “adjacent” and “neighboring,” we request that this difference be explained and made more explicit in the language of the standard.

We also ask for clarification on the meaning of the phrases “adjacent Transmission Operators” and “adjacent Reliability Coordinators,” for the ERCOT interconnection, as neither of these terms is defined. We ask the SDT to clarify that, consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, “adjacent” should not be read to apply to RCs or TOPs that are not “within the same Interconnection.” This change is appropriate because ERCOT does not rely on SPP or MISO for system restoration, and SPP and MISO also do not rely on ERCOT for that purpose.

Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto

Response

Thank you for your comments. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources.

The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Comment	

Most training is conducted on a yearly basis, with certain required training every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required “once per calendar year.” That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around from year to year as needed.

EOP-006-3 R1 states, “Each Reliability Coordinator shall develop, maintain, and implement” while EOP-005-5 R1 states, “Each Transmission Operator shall develop and implement.” We recommend that the “develop and implement” language in EOP-005-3 R1 be used in EOP-006-3 R1 for consistency among the two standards.

Response

Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

The EOP SDT removed “maintain” from Requirement R1 in which the team felt “maintain” is contained in RequirementsR3, R4, and R5. “Implement” replaces the requirements of RequirementsR7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No

Comment

R7: See Duke Energy’s comment regarding the replacement of “annual” with “at least once each 15 calendar months” in response to question 1 above.

Response	
The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining “annual”.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly. We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as: R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.	
Response	
Thank you for your comments. The EOP SDT removed “maintain” from Requirement R1 in which the team felt “maintain” is contained in Requirements R3, R4, and R5. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.	

The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP's restoration plan.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly. We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as: R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.	
Response	
Thank you for your comments. The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources. The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP's restoration plan.	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	

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We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Response

Thank you for your comments. The EOP SDT removed “maintain” from Requirement R1 in which the team felt “maintain” is contained in Requirements R3, R4, and R5. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources.

“Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources.

The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP’s restoration plan.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Comment	

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

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R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Response

Thank you for your comments. The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.

"Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources.

The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP's restoration plan.

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3

Answer	No
Comment	

Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement.

EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement.

We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Response

Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".

The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.

"Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within Requirement R1. The RC obligation is triggered by the use of Blackstart Resources.

The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP's restoration plan.

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No

Comment

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

2. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement. EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Response

Thank you for your comments.
The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining "annual".

The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of RequirementsR7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No

Comment
A. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed. B. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement..EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.
Response
Thank you for your comment. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining "annual". The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
Requirement 8 should NOT be retired. It is a critical step in the Restoration Plan that requires RC approval.	

Response	
Thank you for your comments. The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Comment	
(1) R1 now includes "develop, maintain, and implement" a restoration plan for the RC. We question why "maintain" was included in EOP-006-3, but it only states "develop and implement" for the TOP in EOP-005-3. This is inconsistent language and should be aligned. (2) We disagree with the inclusion of "maintain and implement." Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including three actions, having a plan, maintaining the plan, and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has six sub-parts, which can now be reviewed under three filters – is it documented, is it maintained, and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the six sub-parts. (3) For R3, we agree with the change from 13 calendar months to 15 calendar months to align with other NERC standards. (4) For R7 (formerly R9), we agree with changing annual to 15 calendar months to align with other NERC standards.	
Response	
Thank you for your comment. "Implement" replaces the requirements of R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources. Thank you for your comments. The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources.	

The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements also provides guidance on defining "annual".	
Richard Vine - California ISO - 2	
Answer	No
Comment	
Please see our response to Q1 regarding R1 of EOP-005-3 which we feel are applicable to EOP-006-2 as well.	
Response	
Please see responses to your comments for Q1 regarding Requirement R1 of EOP-005-3.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	
It seems that there was inconsistent use of 'maintain' in R1 between EOP-006-3 and EOP-005-3. We suggest removing the word 'maintain' in R1 since it is redundant with requirement R3. Also M1 would need to be edited to measure that the plan was appropriatel 'maintained' as well as implemented. As stated, it does not verify that the plan was maintained. In the revised R1.2 we just point out that there can be 'adjacent' entities that may not be within the same Interconnection (example: SPP BA/RC and ERCOT BA/RC) that it may not be appropriate or necessary to coordinate restoration plans. One way to handle this may be to specify that coordination must be performed with entities within the same Interconnection, or alternatively allow the restoration plan to dictate which entities are considered adjacent.	

We believe the intent of the proposed R8.1 is to only require participation by TOPs and GOP's who 'have a role' in the restoration plan. There are TOPs and GOP's in the RC Area who may never have a role in restoration activities (aka wind farms or small TOPs). We suggest rewriting R8.1 as: R8.1 Each Reliability Coordinator shall request each Transmission Operator **which has a role** in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least **once** every two calendar years.	
Response	
Thank you for your comments. The EOP SDT removed "maintain" from Requirement R1 in which the team felt "maintain" is contained in Requirements R3, R4, and R5. "Implement" replaces the requirements of Requirements R7 and R8. The intent of "implement" is within R1. The RC obligation is triggered by the use of Blackstart Resources. The EOP SDT determined that the addition of "adjacent" in R1.2 is unnecessary and is captured by the use of "neighboring" in Requirement R1. "Neighboring" gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The EOP SDT did not elect to change the wording contained in Requirement Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOPs restoration plan.	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	No
Comment	
In Requirement R1.2, the proposed revisions establish that the restoration plan must include criteria and conditions for re-establishing interconnections with other Transmission Operators within the Reliability Coordinator's Area, with "adjacent" Transmission Operators in other Reliability Coordinator Areas, and with "adjacent" Reliability Coordinators. The use of the word "adjacent" is more appropriate as it makes the requirement more clear. The SRC suggests a further clarification that is consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, which states that "adjacent" should not be read to apply to RCs or TOPs that are not "within the same Interconnection." The SRC suggests that the words "electrically adjacent" be used throughout the standard. Specifically, the word "neighboring" should be replaced with the word "electrically adjacent" in all instances in the standard (including the Violation Severity Levels), because "electrically adjacent" is clearer than "neighboring"or "adjacent" (alone).	

In addition, the SRC suggests that clarifying changes be made in Requirement 4, Part 4.1, so that it reads as follows: 4.1. If a Reliability Coordinator finds conflicts between its restoration plans and the restoration plans of an adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar days of written notification from the Reliability Coordinator to the adjacent Reliability Coordinator of the identified conflicts. The additional revisions make clear that both the Reliability Coordinator and the adjacent Reliability Coordinator have to resolve any conflicts, and the timing for resolution will also be clear.
Response
Thank you for your comments. The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The EOP SDT has addressed your concern in Requirement 4 and Requirement 4, Part 4.1 as follows: **R4.** Each Reliability Coordinator shall review its adjacent Reliability Coordinator’s restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any adjacent Reliability Coordinator’s restoration plan, the conflicts shall be resolved within 30 calendar days of written notification.
Gregory Campoli - New York Independent System Operator - 2
Answer No
Comment
see comments from IRC/SRC
Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Comment	

Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a RC's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program.

Texas RE recommends clarifying the Reliability Coordinator's obligations to "maintain" a restoration plan. As currently drafted, neither the measure nor VSLs specifies the evidence or severity of an issue associated with the failure to maintain. One possible interpretation of this requirement is that RC's must use the proposed 15 month reviews to ensure their plan includes appropriate criteria and processes for the re-energization of shutdown areas. However, it possible that RCs may have additional or distinct obligations. Texas RE requests that the SDT provide additional information regarding maintenance obligations under this requirement.

Texas RE recommends defining the terms "neighboring" and "adjacent". It is unclear whether or not there is a difference in what those terms mean. Requirement R1 has "neighboring" RC reference but Requirement part 1.2 has "adjacent" referenced. In 4.1 "neighbors" is used (and is assumed to RCs). There appears to not be a requirement to provide the RC plan to neighboring/adjacent TOPs There should be consistency in terms used and it should be well understood by all RCs that adjacent/neighboring is the RC (or RCs) that is (are) touched at the boundary regardless of synchronous or asynchronous connectivity.

Texas RE is concerned that, without parts 1.2,1.3, and 1.4, there may not be clarity provided in roles and responsibilities within a restoration plan. There should be Operating Processes utilized by the RC. The restoration plan should clearly indicate coordination efforts with TOPs and RCs. In the proposed 1.2 (old 1.5) there is a reference to "adjacent" TOPs in other RC Areas but no requirement to provide the RC restoration plan to those adjacent TOPs (nor a requirement for the adjacent RC to provide the plan). This appears to be a gap in reliability if there are criteria for "reestablishing interconnections" with TOPs in other RC Areas. It is unclear whose role or responsibility it is that to provide the information.

Texas Re noticed draft EOP-006-2 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and

Enforcement Program. In the EOP-006-2 draft, compliance Enforcement Authority does not have a section. The reset Time Frame and Evidence retention is section C 1.1. C1.2 is Compliance Monitoring and Enforcement Processes Program (incorrect section and title)
Response
Thank you for your comments. The EOP SDT removed “maintain” from Requirement R1 in which the team felt “maintain” is contained in Requirements R3, R4, and R5. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within R1. The RC obligation is triggered by the use of Blackstart Resources. The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan.

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Comment	
There are multiple references to “neighboring RCs” in the Standard. Can these all be replaced, as appropriate, with the word “adjacent RCs?” If the intent as referenced with the change in R1.2 holds true to the whole Standard then clarifying neighbors to be “direct connection” instead of “just neighbors without electrical adjacency.” This is particularly true for R4 – is it really necessary for Peak to review MISO’s Restoration plan now that we have no electrical connection with them? Old R10.1 (new R8.1): Peak seeks clarification – shouldn’t the new R8.1 follow the same logic of 15 months instead of 24 months so as to keep it in line with new R7 (internal restoration drill training)? Or is the intent that every 15 months RCs train internally but only every 24 months they invite all TOPs and GOPs?	
Response	
Thank you for your comment. The EOP SDT determined that the addition of “adjacent” in Requirement R1, Part 1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan.	

There were no proposed revisions to the language from 10.1 (New R8.1). The EOP SDT decided to keep two calendar years (revised to 24 calendar months for consistency) for drills, exercises and simulations.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Comment	
We support NPCC's comments. In addition, we have the following comments. M4 does not reflect the written notification time requirement (60 days) in R4. We suggest : M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator’s restoration plans, **has provided written notification of any conflicts within 60 calendar days** and resolved any conflicts within 30 calendar days of notification in accordance with Requirement R4. The VSL table for R4 does not address situations where the RC reviews the submitted plans but does not provide written notification of a conflict. (in those situations, the timer for the resolution of conflicts between the plans never starts.) We note that requirements 1 and 2 refer to the 'RC Area restoration plan' whereas the rest of the requirements skip 'Area'.	
Response	
Thank you for your comments. The EOP SDT revised the language in Measure 4, as follows: “Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator’s restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.” The VSL table focuses on the step most salient to reliability, which is the resolution of any identified conflict. The EOP SDT reviewed your comment pertaining to “RC Area” and does not find any revisions are needed.	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	

Answer	No
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Comment	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
FMPA generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.	
Response	
Thank you for your comments. The NERC Glossary of Terms defines Control Center as: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.	

The EOP SDT is discussed the defined term Control Center, which could include the RC and BA. The defined term Control Center could create confusion regarding whether RCs and BAs should be added as an applicable entity; therefore, the EOP SDT decided to use the non-defined term of control center.

Ken Simmons - Gainesville Regional Utilities - 1,3,5

Answer	Yes

Comment

GRU generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.

Response

Thank you for your comments. The NERC Glossary of Terms defines Control Center as: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

The EOP SDT is discussed the defined term Control Center, which could include the RC and BA. The defined term Control Center could create confusion regarding whether RCs and BAs should be added as an applicable entity; therefore, the EOP SDT decided to use the non-defined term of control center.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6

Answer	Yes

Comment

1. For additional clarification, Dominion suggests the following changes to R4; Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered between restoration plans during that review within 60 calendar days of receipt.

2. In Part 4.1, Dominion suggests the following change to clarify when the 30 day period starts:

If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of delivery of written notification.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance: The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Response	
Thank you for your comments. The EOP SDT reviewed your comment and did not find the change was needed. The EOP SDT revised Requirement 4 Part 4.1, as follows: If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days **of receipt of** written notification. Thank you for your comments. NERC will align the templates of the standards.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Comment	
CenterPoint Energy believes that for consistency between the EOP-005-3 and EOP-006-3 proposed standards the language proposed in both R1s should be consistent and use either, ”develop and implement”, or “develop, maintain, and implement”.	
Response	
Thank you for your comment. The EOP SDT removed “maintain” from Requirement R1 in which the team felt “maintain” is contained in Requirements R3, R4, and R5. “Implement” replaces the requirements of Requirements R7 and R8. The intent of “implement” is within Requirement R1.	
David Ramkalawan - Ontario Power Generation Inc. – 5	

Answer	Yes
Comment	
Response	
ALAN ADAMSON - New York State Reliability Council – 10	
Answer	Yes
Comment	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	

Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
Response	

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Comment	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Comment	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Comment	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	

Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Comment	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Comment	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Comment	

Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Comment	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Comment	
EOP-006-3 does not apply to AE and, therefore, we have no opinion.	
Response	

Chris Scanlon - Exelon - 1	
Answer	
Comment	
No Opinion.	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Comment	
This standard is not applicable to Hydro One Networks Inc.	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	
Comment	
EOP-006-2 is applicable to Reliability Coordinators only. CHPD is not registered as a Reliability Coordinator. As such, CHPD does not have an opinion.	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	

Answer	
Comment	
RC only.	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Response	

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No

Comment

R7 requires at least once each 15 calendar months, annual System restoration training for its System Operators. R8 requires two System restoration drills, exercises, or simulations per calendar year. Need to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.

Response

The EOP SDT is not removing the training or drill requirements from this standard. The currently-enforced Requirement R9 is proposed Requirement R7 for EOP-006-3 and the currently-enforced Requirement R10 is proposed Requirement R8 for EOP-006-3.

The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

Richard Vine - California ISO - 2

Answer	No

Comment

Please see comments above which apply to EOP-006 as well.

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
The Violation Severity Level should match the proposed Standard EOP-006-3 Requirement R8 instead of Requirement R8.1.	
Response	
Thank you for your comments. The EOP SDT made the conforming changes.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 – SERC	
Answer	No
Comment	
One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.	
Response	
The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as “a logical action that does not require a standard.” The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, the EOP SDT discussed the content in Requirement R1, Part 1.2 which contains criteria and conditions for re-establishing interconnections.	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. – 1	
Answer	No
Comment	

1. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.	
Response	
The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, the EOP SDT discussed the content in Requirement R1, Part 1.2 which contains criteria and conditions for re-establishing interconnections.	
Clay Young - SCANA - South Carolina Electric and Gas Co. – 3	
Answer	No
Comment	
One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.	
Response	
The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, the EOP SDT discussed the content in Requirement R1, Part 1.2 which contains criteria and conditions for re-establishing interconnections.	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
See comments to #2	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
See comments to #2	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
See comments to #2	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Comment	
See comments to #2	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Comment	
Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Because lack of coordination could have such a large impact on system reliability during system restoration, the requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization with neighboring TOPs and RCs.	
Response	
The EOP SDT discussed your comment and agrees that Requirement R1, Part 1.2 requires the RC to have coordination with other TOPs and RCs.	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	No

Comment	
See answer to Number 2.	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Comment	
R7 requires System Operator training every 15 months and R8 requires two drills, exercises or simulations every calendar year. The NSRF requests that R7 and R8 be combined to to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The SDT can add in the sub-Requirements to capture all concerned parties. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.	
Response	
The EOP SDT reviewed your comment but the two requirements have distinct processes and goals (training vs. drills) and should be kept separated.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	
We support NPCC's comments.	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Comment	
We are supportive of the retirements proposed in EOP-006-3 of R7 and R8.	
Response	
Thank you for your comment and your support.	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Comment	
Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall "implement" a Reliability Coordinator Area restoration plan, Requirements R7 and R8 can, and should, be retired. [CAISO and SPP do not support this comment.]	
Response	
Thank you for your comment and your support.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Comment	
We agree with the proposed retirement of R7 and R8.	
Response	
Thank you for your comment and your support.	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Comment	

1. New M7: Remove the additional 'M7', that is listed above R7
2. New M8: The request to participate is applicable to part 8.1 only in the last sentence, therefore Dominion suggests the last sentence in M8 be written to read as; And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement 8 Part 8.1.

Response

Thank you for your comments. The error has been corrected and the Measure has been updated.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	

Assuming that Requirement R1 is being revised to state that the Reliability Coordinator shall "implement" a Reliability Coordinator restoration plan, Requirements R7 and R8 should be retired.

Response

Thank you for your comment. 'Implement' has been included into Requirement R1.

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Comment	
Response	

Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Comment	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Comment	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Comment	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Comment	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Comment	
Response	

Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Comment	

Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Comment	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Comment	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Comment	
Response	

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Comment	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Comment	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Comment	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Comment	

Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Comment	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes

Comment	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Comment	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Comment	
Consistent with the comments in response to Question 2 above on EOP-005, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a	

Disturbance, but also that if "the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration." As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate: 1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected. In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to "coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization." Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC's restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC's existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following: 1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators	
Response	
The EOP SDT discussed and the high-level strategies are included in Requirement R1 Part 1.1. The EOP SDT discussed your resynchronization comment and agrees that Requirement R1, Part 1.2 requires the RC to have coordination with other TOPs and RCs.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	

Comment	
This standard is not applicable to Hydro One Networks Inc.	
Response	
Chris Scanlon - Exelon - 1	
Answer	
Comment	
No Opinion	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Comment	
EOP-006-3 does not apply to AE and, therefore, we have no opinion.	
Response	

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Comment	
Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R5 and R7 is unecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.	
Response	
The EOP SDT decided to maintain "annual" in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Comment	
SRP recommends clarifying the revision of the next to last bullet of Section 1.2 Evidence Retention. How many previous calendar years is evidence to be retained for?	
Response	
Thank you for your comment. The EOP SDT revised the language in Section 1.2 Evidence Retention to read: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous calendar year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7."	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Comment	
EOP-008 R5.1 has always been a bit ambiguous as to when it triggers a required update of the Operating Plan. "Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle. Language could be modeled off the new language in EOP-005-3 R4. For example, the language could be changed to, "An update and approval of the Operating Plan for backup functionality shall take place withing sixty calendar days to reflect changes in the operating plan to items in R1 that would change the ability to implement the operating plan."	
Response	
Thank you for your comment. As Requirement R1 is currently written, the intent is to keep the plan updated. Therefore, the EOP SDT suggested no change to Requirement R5, Part 5.1.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Comment	
R1: We request further clarification regarding the inclusion of Interpersonal Communications in R1.2.3. Will the the Operating Plan for backup functionality need to also address Alternative Interpersonal Communications? The primary control center for the BA/TOP is required under COM-001-2.1 to have both Interpersonal Communications and Alternative Interpersonal Communications. To follow R1.3, it seems like BA/TOP entities would need to also have Alternative Interpersonal Communications addressed in the Operating Plan for EOP-008-2 in order to keep backup functionality consistent with the primary control center. Also, when operating from the backup, entities still must adhere to Standard COM-001-2.1.	

If Alternative Interpersonal Communications need to be part of the Operating Plan for EOP-008-2 that should be clear to all entities from the Standard so they know what their obligations are. The current version just says Voice communications, and that can mean something very different than having both Interpersonal Communications and Alternative Interpersonal Communications. R5: See Duke Energy's comment regarding the replacement of "annual" with "at least once each 15 calendar months" in response to question 1 above.	
Response	
Thank you for your comments. The EOP SDT does not agree that Alternate Interpersonal Communications should be included in EOP-008. Alternative Interpersonal Communications is included in COM-001-2.1. The EOP SDT decided to maintain "annual" in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Comment	
"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Response	
Thank you for your comment. As Requirement R1 is currently written, the intent is to keep the plan updated. Therefore, the EOP SDT suggested no change to Requirement R5, Part 5.1.	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No

Comment	
“Any changes to any part of the Operating Plan” could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Response	
Thank you for your comment. As Requirement R1 is currently written, the intent is to keep the plan updated. Therefore, the EOP SDT suggested no change to Requirement R5, Part 5.1.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Comment	
“Any changes to any part of the Operating Plan” could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Response	
Thank you for your comment. As Requirement R1 is currently written, the intent is to keep the plan updated. Therefore, the EOP SDT suggested no change to Requirement R5, Part 5.1.	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	No
Comment	

PGE thinks that the 15 month window is too restrictive and will give us less flexibility to schedule the drills outside of storm season, peak load periods, unexpected issues, etc. There is little gained by the more restrictive window, and much flexibility is lost in the ability to work around system demands.

Response
The EOP SDT decided to maintain "annual" in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 – WECC

Answer	Yes
Comment	

Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.

Response
Thank you for your comment. Requirement R6 is about the functionality and Requirement R7 is about the plan itself. Therefore, the EOP SDT suggests no additional changes to these requirements.

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 – WECC

Answer	Yes
Comment	

Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary

functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.	
Response	
Thank you for your comment. Requirement R6 is about the functionality and Requirement R7 is about the plan itself. Therefore, the EOP SDT suggests no additional changes to these requirements.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
The replacement of "annual" with "at least once each 15 calendar months" in R7 introduces additional unnecessary administrative tracking requirements, suggest that this requirement remains an annual requirement.	
Response	
The EOP SDT decided to maintain "annual" in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Comment	
Manitoba Hydro suggests to keep using Voice communications for R1.2.3 as it provides more clarity than Interpersonal Communications and eliminates redundancy with R1.2.2. Other type of communication mediums such as email and web messaging would already be covered under R1.2.2 Data communications.	
Response	

Thank you for your comment. Interpersonal Communications brings the requirement into alignment with COM-001-2.1. The definition of Interpersonal Communications in the NERC Glossary of Terms is: "Any medium that allows **two or more individuals** to interact, consult, or exchange information." Which includes human interaction; the EOP SDT's intent of Requirement R1 Part 1.2.2 Data communications is non-human interaction.	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
FMPA generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.	
Response	
Thank you for your comment. The NERC Glossary of Terms defines Control Center as: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations. The EOP SDT discussed the defined term Control Center, which could include the GOP. This standard requires backup functionality for RCs. BAs, and TOPs. The defined term Control Center could create confusion regarding whether GOPs should be added as an applicable entity; therefore, the EOP SDT decided to use the non-defined term of control center.	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Comment	

GRU generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.

Response	
Thank you for your comment. The NERC Glossary of Terms defines Control Center as: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations. The EOP SDT discussed the defined term Control Center, which could include the GOP. This standard requires backup functionality for RCs. BAs, and TOPs. The defined term Control Center could create confusion regarding whether GOPs should be added as an applicable entity; therefore, the EOP SDT decided to use the non-defined term of control center.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Comment	
We believe the SDT should add language "with respect to loss of control center functionality" in Requirement 7 immediately after "Operating Plan"	
Response	
Thank you for your comment. Based on the Title and the Purpose of EOP-008, the EOP SDT agrees there is no change needed.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Comment	
PJM has concerns with R6 and its implecations to other standards. Specifically, TOP-001-4 and its requirement to maintain redundancy.	

Response	
Thank you for your comments. The EOP SDT discussed and agree that EOP-008, Requirement R6 relates to backup functionality and TOP-001-4 (which is currently in development) refers to data redundancy; therefore, we suggest no changes.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
No comments	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Comment	
CenterPoint Energy generally agrees with and supports the SDT's revisions and clarifications proposed for EOP-008-2. We would like the SDT to consider changing R1.2.2 from, "Data communications" to "Data exchange capabilities" for consistency and alignment with revisions to the upcoming January 2017 enforceable requirements in TOP-001-3 R19 and IRO-002-4 R1 which are required to support the data specification concept in TOP-003-3.	
Response	
Thank you for your comment. After reviewing Commission Order No. 817 and Project 2016-01, the EOP SDT supports your comment for using "data exchange capabilities" to align EOP-008 with TOP-001-3 and IRO-002-4.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Comment	

(1) We agree with the R1 changes from voice communications to Interpersonal Communication capabilities to align with other NERC standards.

(2) We question the need for a change in M1, M2, and M5 from "in force" to "in effect." They appear synonymous.

(3) For R5 and R7, we agree with changing annually to 15 calendar months to align with other NERC standards.

Response
Thank you for your comments. The EOP SDT adopted "in effect" to align with other Measures. The EOP SDT revised the words "in force" to "in effect" for clarity and consistency. The EOP SDT decided to maintain "annual" in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes

Comment

R1

We agree the revision to R1, Part 1.1. prevents a tertiary Requirement (i.e., already included in EOP-008-2, R3 and R4).

We agree that in R1, Part 1.2.3., the defined term "Interpersonal Communications" should be used.

R5 and R7

We are supportive of replacing "annually" with "15 months" and believe it provides added clarity.

Response	
Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-008 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. *The NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Comment	
We agree with EOP-008-2	
Response	
Thank you for your support of the standard.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	
Given the shift in EOP-005-3 and EOP-006-3 away from the mere 'having' a restoration plan to 'developing and implementing' a restoration plan, would it make sense to shift EOP-008-2 R1 away from 'having' to 'developing and maintaining' the Operating Plan? The other requirements concerned with the physical plan remain valid. Should R7 be modified to ensure consistency with R1.5 time requirement? R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]	

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality **is less than or equal to two hours**. 7.2. The backup functionality for a minimum of two continuous hours.
Response
Thank you for your comment. The EOP SDT discussed but agrees there are several requirement parts that address implementation. EOP SDT reviewed 1.5 in Requirement R7 and believes these are separate purposes and should remain as drafted.
ALAN ADAMSON - New York State Reliability Council - 10

Answer	Yes
Comment	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Comment	
Response	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	

Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Comment	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Comment	
Response	
Andrew Gallo - Austin Energy - 6	

Answer	Yes
Comment	
Response	
Tina Garvey - Austin Energy - 4	
Answer	Yes
Comment	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Comment	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Comment	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes

Comment	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Comment	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Comment	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Comment	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Comment	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Comment	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Comment	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Comment	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Comment	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Comment	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	

Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Comment	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	
Comment	
Requires a rework of the language related to the retention of evidence as "previous calendar years" is ambiguous and open to interpretation. Recommend that language related to the retention of evidence be consistent throughout the NERC standard. That is, "…shall retain evidence for the time period since its last compliance audit."	
Response	
Thank you for your comment. The EOP SDT revised the language in Section 1.2 Evidence Retention to read: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous	

calendar year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.”

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Comment	

The term “control center” (Purpose statement, Requirement R1, part 1.3, part 1.5, part 1.6, Requirement R2, Measure M2, Requirement R3, Measure M3, Requirement R4, Requirement R6, Measure M6, part 7.1, Evidence Retention section, and the VSL section) should be capitalized as it is a defined term.

Texas RE recommends revising Requirement R2 to generically refer to any location capable of providing backup functionality as there are cases where there are tertiary control centers developed. Note that having multiple locations where backup functionality may exist is considered to be, or could be considered to be, an exceptional step in supporting reliability and continuity of reliable operations but there should be an expectation of similar reliability expectations coupled with compliance obligations at these locations.

As the goal of the Reliability Standards is Reliability, Texas RE recommends revising Requirement R3 and Requirement R4 “reliable operations and subsequent compliance…”

Texas RE suggests Requirement R3 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "certified Reliability Coordinator operators" with System Operator, which is defined.

Texas RE suggests Requirement R4 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "applicable certified operators" with System Operator, which is defined.

In the “Evidence Retention” section, the changes made to the Measures do not seem to have been provided here (e.g. Measurement M1 changed “in force’ to “in effect” below the R1 but in this section still shows “in force”…multiple instances that need a quality review). Additionally there is inconsistency in the language (e.g. audit versus compliance activity) in this section as compared to EOP-005.

Response

Thank you for your comment. The NERC Glossary of Terms defines Control Center as: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

The EOP SDT discussed the defined term Control Center, which could include the GOP. This standard requires backup functionality for RCs. BAs, and TOPs. The defined term Control Center could create confusion regarding whether GOPs should be added as an applicable entity; therefore, the EOP SDT decided to use the non-defined term of control center.
As written in Requirement R2, you can have a copy of your backup plan at any backup site. It is not limited.

The EOP SDT discussed and changed “depend on” to “applicable to.” The intent was not to have the backup facility “depend on” the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
Requirement R3 is written specific to a RC function. Use of the defined term (System Operator) introduces the BA and TOP system operator.

Requirement R4 is written specific to the BA and TOP functions. Use of the defined term (System Operator) introduces the RC.
The EOP SDT adopted “in effect” to align with other measures and for added clarity and consistency.

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Comment	
We support NPCC's comments.	
Response	
Please see responses to NPCC's comments.	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	No
Comment	
The SRC suggests that the VSLs for EOP-00-3 be clarified as follows: R1 – Severe VSL: The Transmission Operator does not have an approved restoration plan OR The Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1. R3 – Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words "or confirmation of no change" in all of the VSLs to make the language consistent with the deletion of Requirement R3.1.	
Response	
Thank you for your comment. As written, "The Transmission Operator has an approved restoration plan, but failed to implement it," it is implied that a disturbance occurred that required the utilization of your restoration plan. For VSL of Requirement R3, the EOP SDT has made the deletion of "or confirmation of no change."	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Comment	
(1) For the requirements that added “implement” to the requirement, we disagree with the corresponding changes to the VRFs and VSLs. The reasons for disagreement are captured in previous comments. (2) For the requirements that were proposed to be retired or requirements that had timelines clarified, we agree with the corresponding VRFs and VSLs.	
Response	
Thank you for your comments. Please see the drafting team’s response in your previous comments.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
EOP-005-3 R3: Adjust the VSLs to match R3 due to the striking of R3.1. EOP-005-3 R4: **Moderate VSL:** The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 91 calendar days and 120 calendar days of an **unplanned** change. OR The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator at least 20 calendar days prior to a **planned** change. EOP-005-003 R4: **High VSL**: The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 121 calendar days and 150 calendar days of an **unplanned** change. OR	

The TOP failed to update and submit its restoration plan that would affect implementation to the Reliability Coordinator at least 10 calendar days prior to a **planned** change. EOP-005-003 R4: **Severe VSL:** The TOP has failed to update and submit its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator within 150 calendar days of an **unplanned** change. OR The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator prior to a **planned** BES modification. EOP-006-3 R8: The VSL should match the Standard Requirement R8, not R8.1.
Response
For VSL of Requirement R3, the EOP SDT has made the deletion of “or confirmation of no change.” The EOP SDT has updated Requirement R4 to read as below and VSLs have been updated accordingly; R4 Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006 EOP-006-3 R8 VSL; The EOP SDT agrees with your comment and made conforming changes.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Comment	

R4: Duke Energy suggests that the drafting team revisit the language for Severe VSL for R4. It appears that the phrase *"to a planned BES modification"* was left in the VSL, whereas the language used in the other VSL(s) use *"to a planned change".*	
Response	
R4 Part 4.2 was updated as; 4.2 Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006. Therefore the Severe VSL was updated to read as; The Transmission Operator failed to update and submit it revised restoration plan to the Reliability Coordinator prior to a planned permanent BES modification.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC).	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Response	
Thank you for your comments.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Comment	
For EOP-005-3 R1 and EOP-006-2 R1 Severe VSLs, SRP recommends removing the verbiage regarding implementation of the plan. For EOP-005-3 R2, the first 3 VSLs are based on a discrete number, while the Severe VSL also includes the term "half". That causes a potential for contradiction. For example, if an approved restoration plan only identifies 2 entities and 1 of them is not notified of changes, that meets the criteria for both the Lower VSL and the Severe VSL.	

Response	
The EOP SDT reviewed your comments for the Severe VSLs for EOP-005-3 R1 and EOP-006-2 and believes these VSLs should remain as they pertain R1 which requires implementation of the restoration plans.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Comment	

ReliabilityFirst provides the following comments for the **EOP-005-3** VSLs:

1. VSL for R1
    i. Requirement R1 has 9 sub-parts but the high VSL only mentions missing 3 sub-parts. This leaves a gap in cases where an entity fails to comply with 4 or more sub-parts. RF suggest the following as an additional “OR” VSL to the Severe VSL
        a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.
2. VSL for R6
    i. To further clarify the timing of the High VSL, RF recommends the following modification for the High VSL:
        a. The Transmission Operator performed the verification but did not complete it within [six years].
3. VSL for R8
    i. Since Requirement R8 has a timing component as well “…training at least once each 15 calendar months…”, RF recommends adding additional “OR” VSLs to the Severe VSL level as follows:
        a. Severe VSL - The Transmission Operator failed to include within its operations training program, System restoration training at least once within 15 calendar months for its System Operators.

4. VSL for R12

   i. To be consistent with the language in Requirement R12, RF recommends the following language for the Severe VSL

      a. Each Generator Operator with a Blackstart Resource failed to have documented procedures for starting each Blackstart Resource and energizing a bus.

ReliabilityFirst provides the following comments for the **EOP-006-3** VSLs:

1. Requirement R2

   i. RF request clarity around the phrase "or revision" at the end of Requirement R2. Since the RC must perform a review of the restoration plan every 15 calendar months according to Requirement R3, is this considered a revision (thus prompting the RC to distribute the restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days)? If this is the intent, RF recommends the following revision for the SDTs consideration.

      a. R2 - The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation, revision [or annual review].

1. VSL for R5

2.

   i. Since the word "notification" is not in Requirement R5, RF suggests removing the second "OR" VSL from each of the VSL Categories and add the phrase "with stated reasons" to the first VSL. Listed below is an example of this addition to the Lower VSL Category:

      a. The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans [with stated reasons] from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt.

Response

EOP-005 VSL
1. VSL R1 - The EOP SDT reviewed your comment and has updated the Severe VLS to read as; The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
2.VSL for R6 - High VSL no change made, the language in the VSL of “required timeframe” is a reference to the time frame within Requirement R6.
3.VSL for R8 - The EOP SDT reviewed your comment and made conforming changes.
4. VSL forR12 - The EOP SDT reviewed your comment and did not believe changes need to be made to this VSL.

EOP-006-3
1. R2 and R3 comments - The EOP SDT believes if there is an RC review completed in R3 and there is a revision made to the restoration plan, then the RC shall follow the distribution requirements in R2.
2. VSL for R5 - The EOP SDT reviewed your comments, but agreed that ‘notified’ is in M5; and, therefore, did not make any changes. The EOP SDT did agree with the revisions suggested to include “with stated reasons for disapproval, and made the conforming change.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No

Comment

It is suggested that the VSLs for EOP-005-3 be revised for clarification as follows:

R1--Severe VSL: The Transmission Operator does not have an approved restoration plan OR the Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1.

R3--Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words “or confirmation of no change” in all of the VSLs to make the language consistent with the deletion of Part 3.1.

Response

Thank you for your comments. The EOP SDT made the following revisions to Requirement R1 Severe VSL: "The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1." The EOP SDT deleted the words "or confirmation of no change" from all four levels of VSLs.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Comment	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	No
Comment	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Comment	
Note the SDT will need to make changes to EOP-005-3 VSLs to align with FE proposed requirement text changes if the changes are accepted.	

Response	
Thank you for your comment.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
No comments	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Comment	
EOP-005-3: 1. All R3 VSLs should be revised to read as 'mutually agreed upon'. 2. R4: High VSL should be revised to read as 'between 121 calendar days and 150 calendar days…'.	
Response	
Thank you for your comments. The VSLs read as you commented to.	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Comment	

EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Response	
Thank you for your comments. The VSLs read as you commented to.	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	Yes
Comment	

EOP-005-3:

All R3 VSLs should be revised to read as ‘mutually agreed upon’.

R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Response	
Thank you for your comments. The VSLs read as you commented to.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Comment	

Comments: EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Response	
Thank you for your comments. The VSLs read as you commented to.	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Comment	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes

Comment	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Comment	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Comment	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
Response	
Richard Vine - California ISO - 2	

Answer	Yes
Comment	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Comment	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Comment	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Comment	
Response	

Chris Scanlon - Exelon - 1	
Answer	Yes
Comment	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	

Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Comment	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Comment	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes

Comment	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Comment	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Comment	
Response	
Tina Garvey - Austin Energy - 4	
Answer	Yes
Comment	

Response	
Andrew Gallo - Austin Energy - 6	
Answer	Yes
Comment	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Comment	

Response
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Comment	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Comment	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Comment	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Comment	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Comment	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Comment	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	

Answer	
Comment	
N/A	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Comment	
EOP-005: Consistent with Texas RE's comments above, the SDT should separate the development and implementation of restoration plans under EOP-005-3's requirements. If the SDT does this, these changes should also flow through the affected VSLs. However, the SDT should at a minimum revise the language in the VSL to reference the revised standard requirements in R1. That is, the VSL, as currently drafted, uses the term "comply." Rather, as Texas RE reads the elements in the VSL, the Lower, Medium and High categories reference a TOP's obligation to incorporate the various restoration plan elements specified in parts R1.1 through R1.9. As such, Texas RE recommends revising the VSLs to make clear that the each violation threshold applies for TOPs not including required elements in their plan. For example, the Lower VSL should read: "The [TOP] has an approved plan, but the plan is missing one of the required elements specified in the requirement parts within Requirement R1." EOP-006: Please see the comments on EOP-006-3, R1 above. The proposed VSLs do not address a RC's maintenance obligations under R1. EOP-008: The Requirement R2 Severe VSL should say "control locations".	
Response	
Thank you for your comments. The EOP SDT made the following revisions to Requirement R1 Severe VSL: "The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1."	

The EOP SDT deleted the words “or confirmation of no change” from all four levels of VSLs.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Comment	
N/A	
Response	

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Comment	

In EOP-005-3 the effective date of the restoration plan should be defined. Requirement R4 only takes into account the update and the submittal of the TOP plan to the RC for approval. Requirement R4 does not define the effective date of the TOP plan. On reading between the lines, it can be understood that the restoration plan should be effective no more than 120 (90+30) days following an unplanned System modification and prior to the implementation of a planned System modification.

The Drafting Team should consider the addition of a phrase to Requirement R4 to indicate that the TOP plan becomes effective following its approval by the RC.

Requirement R6 of EOP-005-3 requires verification and testing of the restoration plan at least once every five years.

The *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans* recommended the re-verification or re-testing of the restoration plan when there are System changes that could impact the viability of the plan.

The Drafting Team should consider the updating of Requirement R6 according to the recommendation or explain why this recommendation was not retained.

The phrase "or an energized island has been formed on the BES within the Reliability Coordinator Area" needs to be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3.

The spirit of this standard applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators. Does the "energized island" refer to an island formed that bridges boundaries between two TOPs or an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island solely in the context of a partial outage?

Response

Thank you for your comments. The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements. The EOP SDT vetted Requirement R6 and the *FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.* These were recommendations that the EOP SDT considered. The posting supporting document, Consideration of Issues and Directives, address this issue: "The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan (these also have to be submitted to the RC for review), 3) include within its operations training program annual System restoration training for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC has to 1) review its restoration plan within 13 calendar months of the last review, 2) review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed out when there are system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System and is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, they are both continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation."
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Comment	

EOP-005-3 in Section C, 1. Compliance Monitoring Process, that the data/retention time frame for R1 (first bullet) is since the "last monitoring activity". This is a moving target for tracking evidence retention. EOP-006-3 does not have the same retention period for the RC similar Requirement. It remains as the "last compliance audit". Would suggest that the drafting team return the retention language for EOP-005-3 R1 back to the 'last compliance audit'.	
Response	
Thank you for your comments. The language has been revised back to "last compliance audit."	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	
Comment	
Not applicable.	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Comment	
None.	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Comment	

The webinar for Project 2015-08 mentioned that the proposed revisions to EOP-005 and -006 to address the Recommendations from the ***FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.*** In that regard, Recommendation #2 stated:

2. Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits. In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new blackstart generator location or on redefinition of a cranking path). **[Section IV.G]**

R6 states that: "Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years…."while **M6** goes on to state that: "Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with **R6**."

If the SDT's intent is to have the Transmission Operator verify its plan following an update triggered by **R4**, then APS recommends requirement R6 be revised to more clearly indicate this expectation as follows:

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years or as triggered by a revision to its restoration plan following a System modification as defined under requirement R4. Such analysis, simulations or testing shall verify:…"

Response

Thank you for your comments.

The EOP SDT vetted Requirement R6 and the *FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.* These were recommendations that the EOP SDT considered. The posting supporting document, Consideration of Issues and Directives, address this issue:

"The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan (these also have to be submitted to the RC for review), 3) include within its operations training program annual System restoration training for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC has to 1) review its restoration plan within 13 calendar months of the last review, 2) review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed out when there are system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System and is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, they are both continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation."

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Comment	
None.	
Response	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	
Comment	

None
Response
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance
Answer
Comment
Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement
Response
Thank you for your comment. Consistent with the revision to Requirement R1, the EOP SDT intends to underscore the need for Transmission Operators to utilize their restoration plans. The evidence identified in this Measure is exemplary and not exclusive and its inclusion is consistent with the Standards Process Manual's intended purpose of a Measure. The SPM states that a Measures "[p]rovides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirements."
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane
Answer
Comment
No comments
Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Comment	

The two separate postings caused confusion because the same project has different due dates and overlapping comment periods. We strongly recommend delaying the posting until all standards are ready. We have concerns that the announcements to industry were not clearly announced and stakeholders may not be aware of the two separate and distinct deadlines for submitting comments and balloting on this project.

Thank you for the opportunity to comment.

Response

Thank you for your comments. The ballot period for all four standards will be the same; however, EOP-004 and EOP-008 will announce at a separate time, due to being in final ballot. EOP-005 and EOP-006 will post previous to allow for comment period.

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	
Comment	

ISO-NE voted Negative on EOP-005-3 and EOP-006-3; this is in support of comments submitted here as a member of the SRC; if comments submitted are addressed, ISO-NE would be supportive of the revised Standards.

Response

Thank you for your comments. Please see responses to your comments.

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	
Comment	

1. In R2 and M2 of EOP-005-3, it is not clear who "their" is referring to in each statement. **2. There are several references to 15 calendar months throughout EOP-005-3. Changing the time period to 15 months does not enhance reliability but does have other negative impacts. In R3, entities already have a set period identified by their RC as to when their restoration plans are due. In R8, changing the requirement from annually to 15 months adds a significant level of complexity by requiring tracking of individual rolling time windows for each operator.** **3. In R8.5 of EOP-005-3, training operators on the transition back to normal operations does not provide a reliability benefit commensurate with the level of effort required to develop training. In addition, operator training content is established using the Systematic Approach to Training as required by PER-005-2, R1. Adding training requirements outside of SAT and the PER standard is contrary to the intent of PER-005 and the philosophy of the systematic approach.**	
Response	
Thank you for your comments. The "their" is referring to the entities identified in the TOP's approved restoration plan. "Each transmission Operator shall provide *the entities identified in its approved restoration plan* with a description of any changes to their…" This is from the original language in EOP-005-2. This EOP SDT made no revisions to that language. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". The EOP SDT held extensive discussions on the training requirements of EOP-005. The training requirements are being retained in EOP-005, as it is specific training with high impact, low occurrence. The PER-005 standard entails more of training processes.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Comment	

Texas RE noticed EOP-005-3 Requirement R2 only appears to only apply when there is a change to entities' roles. Texas RE is concerned those entities where there is not a change would not receive an updated restoration plan and thus have a different plan than other entities. Texas RE recommends providing an updated restoration plan to all entities identified in the plan if there are any changes to the plan. There should be information indicating a change or "no change" in the roles.

Texas RE noticed the term "system" is not capitalized in EOP-005-3 Requirements R1.1 and R1.2, but it is capitalized in the RSAW. Since "system" is a defined term in the NERC Glossary, and to be consistent with the RSAW, Texas RE recommends capitalizing the term.

Texas RE noticed EOP-005-3 is uses the term "Disturbance" but EOP-006 has no reference to a "Disturbance". Texas RE inquires as to why EOP-006-3 does not mention "Disturbance".

Texas RE is concerned with the language in EOP-005-3 Requirement R9 that says: "that are outside of their normal tasks". Specific system restoration training should always take place regardless of whether or not the unique tasks are outside [System Operators'] normal tasks". Texas RE is concerned training might not take place if registered entities do not consider System restoration a unique task.

Texas RE requests, in the future, that a full redline be provided for every project. If it is not clear what changed, the requirement language cannot be fully evaluated. Also, Texas RE requests rationale for the changes.

Response

Thank you for your comments.

The EOP SDT understands Requirement R2 to require a TOP to provide all entities identified in its restoration plan with a description c any change to their roles and specific tasks. The requirement does not state that the TOP provide this to only those entities having a change, but to all entities identified in its restoration plan.

EOP-005 Purpose; Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

EOP-006 Purpose; Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

In EOP-005 the restoration plan is enabled if the Disturbance has occurred, and EOP-006 is applicable to the RC to direct the 'coordination of the System restoration process'.

The standard has been updated for "System" to be capitalized.

Requirement R9 training is specific to field switching personnel that perform unique tasks associated with the TOPs restoration plan that are outside of their normal tasks, it does not pertain to System Operators. EOP-006-3, Requirement R7 requires the RC to have annual System restoration training for its System Operators, and Requirement R8 requires the RC to have two System Restoration drills which shall include TOPs and GOPs; and, therefore, the EOP SDT believes the System Operators will still receive System restoration training. Additionally, RC System Operators are subject PER-005-2 and restoration tasks would be subject to inclusion in the entities systematic approach to training based training program.

The EOP SDT has created rationale boxes and a mapping document for this additional ballot and posting, which will include all changes that have been made. A full redline to each last-approved standard was included on the project page during the initial comment/ballot period. The additional comment/ballot periods will include redlines to the last posted, and the final ballot period will have final redlines to the last approved standards.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	

Comment

None.

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1

Answer	

Comment

No additional comments.
Response
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	
Comment	

We support NPCC's comments. In addition we have the following comments.

Comments regarding EOP-006-3 and the concept of "energized island":

The phrase “or an energized island has been formed on the BES within the Reliability Coordinator Area” should be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3. As argued in question 1, we support this concept in EOP-006-3 and would like this concept extended to EOP-005-3. However, we would like the concept to be clarified in order to set clear expectations and a common understanding around this concept.

We note, for example, that the spirit of EOP-006-3 applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators.

RC- RC : As phrased, would an island on the BES that lies across two RC boundaries trigger R1? The third sentence implies the affirmative. If so, it could be clearer to replace the "within the RC Area" by "within **or partly within** the RC Area" or some other variant.

RC -TOP : Does the concept of “energized island” distinguish an island that bridges boundaries between two TOPs and an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island in R1 solely in the context of a partial outage?

Response

Thank you for your comment. The EOP SDT discussed your comment. An energized island that has been formed on the BES within the RC area could be an energized island formed between TOPs in the RC area, or it could also be an energized island formed in one TOP area within the RC area. There are multiple events that could occur with “energized islands” within an RC area, and each event/outag will have to be addressed differently. An electrical island is not solely in the context of a partial outage. There are several scenarios where an energized island could be formed as part of a wide area outage.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	09/26/2016 – 11/09/2016
10-day final ballot	12/01/2016 – 12/12/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.”

Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction to maintain the continuity of the BES	TOP	System wide voltage reduction of 3% or more.
Firm load shedding resulting from a BES Emergency	RC, BA, TOP	Firm load shedding ≥ 100 MW.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,000 MW in the ERCOT Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

<table>
<tr><th colspan="3">EOP-004 Attachment 2: Event Reporting Form
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 “… (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or Applicable Governmental Authority).”</th></tr>
<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td>1.</td><td>Entity filing the report include:
Company name:
Name of contact person:
Email address of contact person:
Telephone Number:
Submitted by (name):</td><td></td></tr>
<tr><td>2.</td><td>Date and Time of recognized event.
Date: (mm/dd/yyyy)
Time: (hh:mm)
Time/Zone:</td><td></td></tr>
<tr><td>3.</td><td>Did the event originate in your system?</td><td>Yes ☐ No☐ Unknown ☐</td></tr>
<tr><td></td><td colspan="2">Event Identification and Description:</td></tr>
</table>

<table>
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<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td>4.</td><td>(Check applicable box)
☐ Damage or destruction of a Facility
☐ Physical Threat to its Facility
☐ Physical Threat to its BES control center
☐ Unplanned BES control center evacuation
☐ Public appeal for load reduction
☐ System-wide voltage reduction
☐ BES Emergency:
   ☐ firm load shedding
   ☐ voltage deviation on a Facility
   ☐ uncontrolled loss of firm load
☐ System separation
☐ Generation loss
☐ Complete loss of off-site power to a nuclear generating plant (grid supply)
☐ Transmission loss</td><td>Written description (optional):</td></tr>
</table>

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<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td></td><td>☐ Unplanned BES control center evacuation
☐ Complete loss of Interpersonal Communication capability at a BES control center
☐ Complete loss of monitoring or control capability at a BES control center</td><td></td></tr>
</table>

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

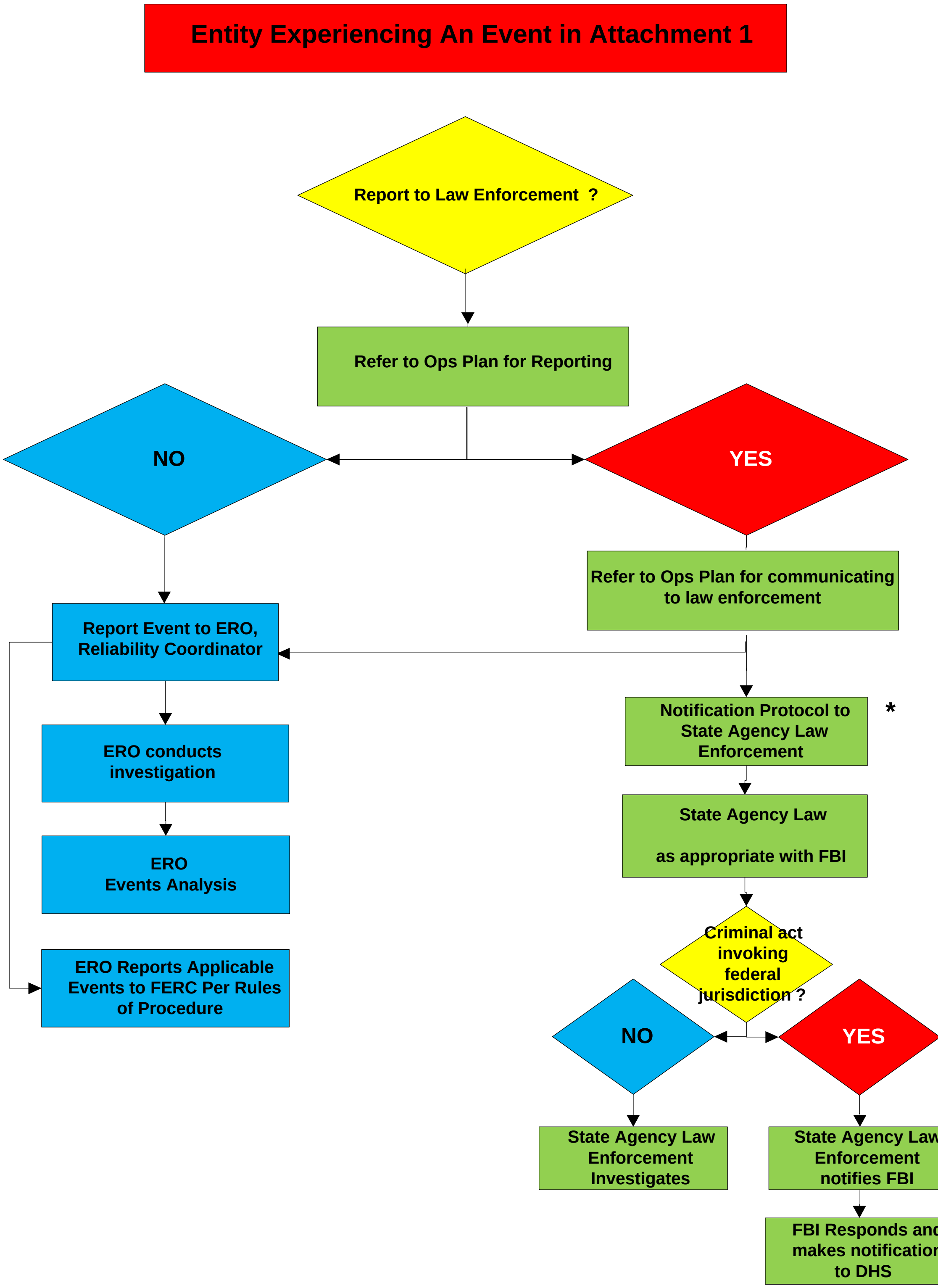
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
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NERC Board (Board) adoption	February 2017

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This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

~~6. **Background:** NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:~~

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in~~

~~updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

~~**7. Standard-Only Definition:** None~~

B. Requirements and Measures

~~**Rationale for Requirement R1:** Text~~

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2~~ ~~3~~ 4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

~~**Rationale for Requirement R2:** Text~~

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday ~~local time~~). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a~~,~~ copy of the completed EOP-004-~~3~~ 4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday ~~local time~~). ~~(R2)~~

~~**Rationale for Requirement R3:** Text~~

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.
~~R3.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~OR~~ ~~The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.~~ ~~OR~~ ~~The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.~~

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.”

Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a~~ its Facility. ~~Do not report theft unless it degrades normal operation of a Facility.~~
Physical threats to ~~a~~ its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~ its BES control center.
~~BES Emergency requiring public~~ Public appeal for load reduction	~~Initiating entity is responsible for reporting~~BA	~~Public appeal for load reduction event.~~Public appeal for load reduction to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction to maintain the continuity of the BES	~~Initiating entity is responsible for reporting~~TOP	System wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual f~~Firm load shedding resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~RC, BA, TOP	~~Manual firm~~ Firm load shedding ≥ 100 MW.
~~BES Emergency resulting in automatic firm load shedding~~	~~DP, TOP~~	~~Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).~~
BES Emergency resulting in ~~Voltage~~ voltage deviation on a Facility	TOP	~~Observed within its area a~~ A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
Uncontrolled ~~Loss~~ loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled ~~Loss~~ loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of~~-~~: ≥ 2,000 MW ~~for entities~~ in the Eastern, ~~or~~ Western, or Quebec Interconnection OR ≥ 1,000 MW ~~for entities~~ in the ERCOT ~~or Quebec~~ Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability affecting a staffed BES control center for 30 continuous minutes or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss~~Complete loss~~ of monitoring or control at ~~capability affecting~~ a BES control center for 30 continuous minutes or more. ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to ~~a~~ its Facility ☐ Physical Threat to ~~a~~ its BES control center ☐ Unplanned BES control center evacuation ☐ Public appeal for load reduction ☐ System-wide voltage reduction ☐ BES Emergency: ~~☐ public appeal for load reduction~~ ~~☐ system-wide voltage reduction~~ ☐ ~~manual~~ firm load shedding ☐ ~~automatic firm load shedding~~voltage deviation on a Facility ☐ uncontrolled loss of firm load ~~☐ Voltage deviation on a Facility~~ ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer~~	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		Comments
	~~Paths (WECC only)~~ ~~☐ Loss of firm load~~ ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ ~~unplanned~~ Unplanned BES control center evacuation ☐ Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability at a BES control center ☐ Complete loss of monitoring or control capability at a BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events~~

~~as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**Data Gathering**~~

~~The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~ 4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC

- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~Present expectations of the industry under CIP-001-1a~~:

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~Coordination of Local and State Law Enforcement Agencies with the FBI~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

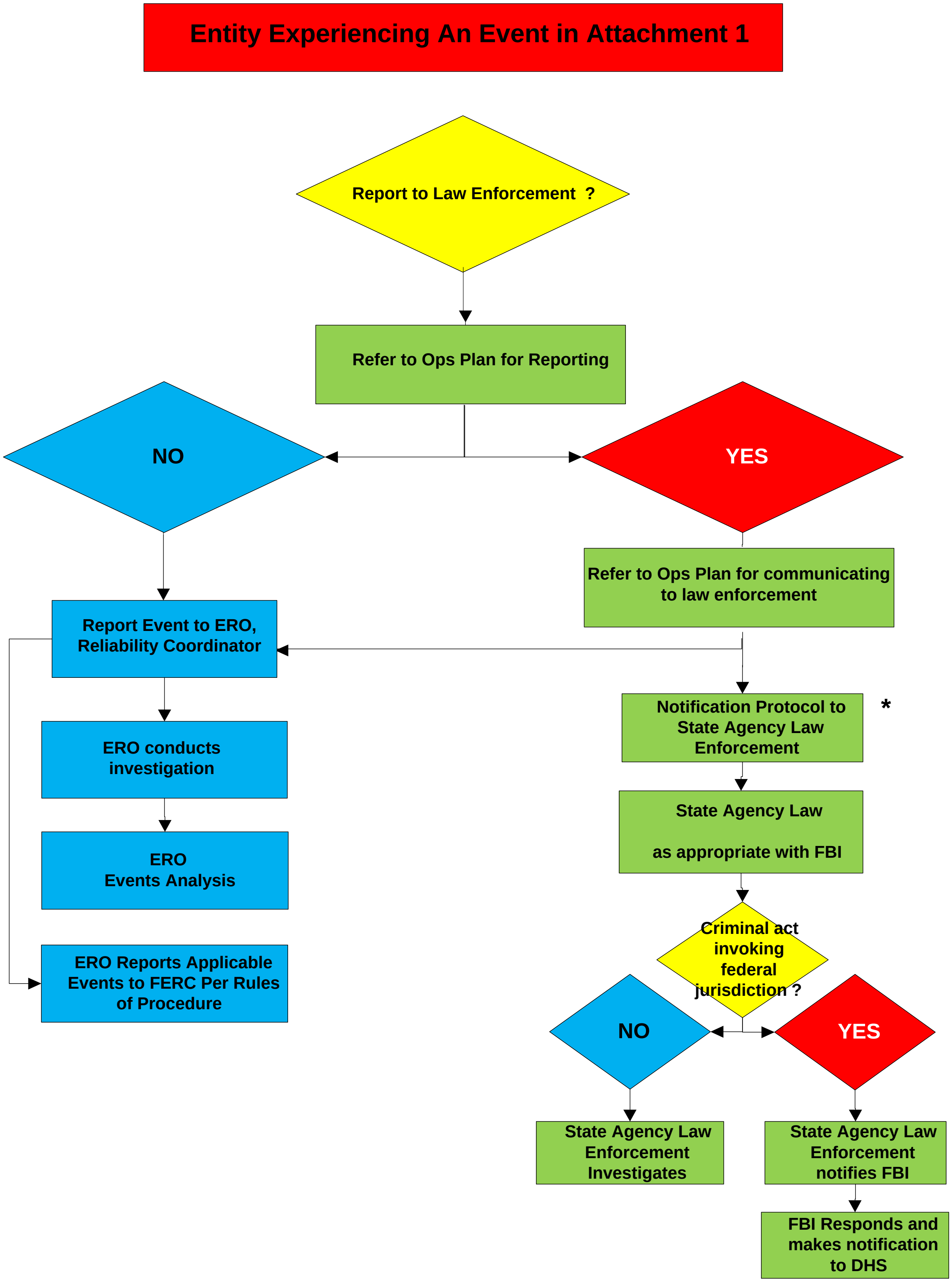
~~Coordination of Local and Provincial Law Enforcement Agencies with the RCMP~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~A Reporting Process Solution – EOP-004~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

~~**Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts**~~

~~Introduction~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.~~

~~The standards listed under the SAR are:~~

~~CIP-001 — Sabotage Reporting~~

~~EOP-004 — Disturbance Reporting~~

~~The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.~~

~~The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.~~

~~Summary of Concepts and Assumptions:~~

~~**The Standard:**~~

- ~~Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System~~
- ~~Provides clear criteria for reporting~~
- ~~Includes consistent reporting timelines~~
- ~~Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting~~
- ~~Provides clarity around of who will receive the information~~

~~**Discussion of Disturbance Reporting**~~

~~Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:~~

1. ~~An unplanned event that produces an abnormal system condition.~~
2. ~~Any perturbation to the electric system.~~
3. ~~The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.~~

~~Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and~~

~~developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

~~Bolts removed from transmission line structures~~

~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~

~~Destruction of Bulk Electric System equipment~~

~~**What about sabotage?**~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.~~

~~Collection of Reportable Information or "One stop shopping"~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

~~ill assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

2015-08 Emergency Operations – EOP-004-4

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Operations; EOP-004-4 – Event Reporting**. The electronic form must be submitted by **8 p.m. Eastern, Thursday, September 8, 2016.**

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Sean Cavote (via email), or at (404) 446-9697.

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT), including the recommendation to revise EOP-004-3 Attachment 1, and retire Requirement R3.[1] The EOP standards drafting team (SDT) considered those recommendations, along with additional input from the industry during the comment period on the project Standard Authorization Request (SAR) for this project. Additionally, the SDT has entered into collaborative efforts among NERC and the U.S. Department of Energy (DOE) to better align reporting requirements pursuant to EOP-004-3 and OE-417. Based on those inputs, the SDT proposes the changes to EOP-004-3 as indicated in this posting.

With respect to DOE collaboration, the SDT has discussed with DOE changes that would be necessary to EOP-004 Attachment 1 and to OE-417 to more closely align EOP-004-4 Attachment 1 Reportable Events with events reported on OE-417. Based on those discussions and the changes proposed in this posting, the SDT and DOE have made significant progress in harmonizing reporting requirements, which would relieve many entities from having to report Reportable Events on both forms. That collaboration continues, but it is important to note that **regardless of whether OE-417 is harmonized with EOP-004-4 Attachment 1, entities will be required to report all Reportable Events as required by EOP-004-4**.

The EOP SDT recommends the following changes to EOP-004-3:

- Update and clarify language in Requirements R1 and R2
- Retire Requirement R3
- Revise Attachment 1: Reportable Events and Attachment 2: Event Reporting Form

[1] The review included EOP-004-3, EOP-005-2, EOP-006-2 and EOP-008-1 to evaluate, for example, whether the requirements are clear and unambiguous. Recommended revisions to EOP-005-2, EOP-006-2, and EOP-008-1 have been posted for comment and ballot in a separate posting.

Update and Clarify Requirements R1 and R2

The SDT proposes a conforming edit in Requirement R1 to reference the correct version number of EOP-004-4 assuming EOP-004-4 ultimately is approved. Specifically, reference to “EOP-004-3” has been changed to “EOP-004-4.” That conforming change also is made to Measure M1.

The SDT proposes to clarify in Requirement R2 that each Responsible Entity shall report events “specified in EOP-004-4 Attachment 1 to the entities specified” in its Operating Plan. The SDT proposes this addition to ensure the Responsible Entity is reporting on the event types and thresholds from EOP-004-4 Attachment 1. Additionally, the SDT proposes to clarify what constitutes a weekend for the purpose of implementing the requirement, i.e., “4 PM local time on Friday to 8 AM local time on Monday.” The SDT proposes similar language and additional clarifications in Measure M2.

Retire Requirement R3

The SDT recommends retiring Requirement R3 under Criterion B1, administrative, because it requires responsible entities to perform a function that is administrative in nature, does not support reliability, and is needlessly burdensome. The SDT notes that contact lists are administrative in nature and should not be part of a mandatory reliability standard.

Revise Attachment 1: Reportable Events and Attachment 2: Event Reporting Form

The SDT proposes several changes to the Event Type, Entity with Reporting Responsibility, and Threshold for Reporting in response to SAR comments and its own analyses. The SDTs changes intend to: clarify appropriate Responsible Entity responsibilities; eliminate duplicative reporting by the Generator Operator (GOP) and Balancing Authority (BA); clarify Generation loss criteria specific to Quebec Interconnection; and align reporting requirements OE-417 where appropriate. The SDT provided its reasoning in the redlined standard, also repeated here:

- System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.
- Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability and determined that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.
- Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.”
- Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control at a BES control center for 30 continuous minutes or

more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

The SDT proposes several changes to Attachment 2 to clarify to whom the Event Reporting Form should be submitted and to more appropriately describe the “Event Identification and Description” field on the form.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the recommendation to retire EOP-004,-3 Requirement R3? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

5. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

   Comments:

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were not revised. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. .
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement
Reminder
Project 2015-08 Emergency Operations
EOP-004-4

Initial Ballot and Non-binding Poll Open through September 8, 2016

Now Available

An initial ballot for **EOP-004-4 - Event Reporting** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, September 8, 2016**.

Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll by clicking here. If you experience any difficulties in using the electronic form, contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations
EOP-004-4

Formal Comment Period Open through September 8, 2016
Ballot Pools Forming through August 23, 2016

Now Available

A 45-day formal comment period for **EOP-004-4 – Event Reporting**, is open through **8 p.m. Eastern, Thursday, September 8, 2016**.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Tuesday, August 23, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 30 – September 8, 2016**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Sean Cavote (via email) or at (404) 446-9697.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/62)
Ballot Name: 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 IN 1 ST
Voting Start Date: 8/30/2016 12:01:00 AM
Voting End Date: 9/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 283
Total Ballot Pool: 342
Quorum: 82.75
Weighted Segment Value: 80.32

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	53	0.746	18	0.254	0	4	14
Segment: 2	9	0.7	4	0.4	3	0.3	0	1	1
Segment: 3	74	1	48	0.814	11	0.186	0	1	14
Segment: 4	23	1	16	0.889	2	0.111	0	0	5
Segment: 5	85	1	49	0.754	16	0.246	1	1	18
Segment: 6	45	1	32	0.8	8	0.2	0	1	4
Segment: 7	3	0.1	1	0.1	0	0	0	0	2
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.8	7	0.7	1	0.1	0	0	1
Totals:	342	7.1	215	5.703	59	1.397	1	8	59

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Duke Energy	Doug Hils		Negative	Third-Party Comments
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Matt Stryker	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Comments Submitted
3	AEP	Aaron Austin		None	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Dehn Stevens		None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Negative	Comments Submitted
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		None	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Finn		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		Negative	No Comment Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		Affirmative	N/A
5	Empire District Electric Co.	Michael kidwell		None	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		None	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Third-Party Comments
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Alyson Slanover	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 342 of 342 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/62)
Ballot Name: 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 NBP IN 1 NB
Voting Start Date: 8/30/2016 12:01:00 AM
Voting End Date: 9/8/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 320
Quorum: 81.56
Weighted Segment Value: 81.19

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	83	1	45	0.789	12	0.211	12	14
Segment: 2	8	0.4	2	0.2	2	0.2	3	1
Segment: 3	73	1	41	0.854	7	0.146	10	15
Segment: 4	21	1	11	1	0	0	5	5
Segment: 5	77	1	38	0.776	11	0.224	10	18
Segment: 6	41	1	27	0.771	8	0.229	3	3
Segment: 7	3	0.1	1	0.1	0	0	0	2
Segment: 8	3	0.3	3	0.3	0	0	0	0
Segment: 9	2	0.2	2	0.2	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	9	0.8	7	0.7	1	0.1	0	1
Totals:	320	6.8	177	5.691	41	1.109	43	59

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Matt Stryker	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	None	N/A
1	JEA	Ted Hobson	Joe McClung	None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Dave Thomas		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Aaron Austin		None	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Dehn Stevens		None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Kissimmee Utility Authority	Anthony Darnell		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Negative	Comments Submitted
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Abstain	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		None	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Matthew Finn		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Abstain	N/A
5	Orlando Utilities Commission	Richard Kinas		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Abstain	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Alyson Slanover	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 320 of 320 entries

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations
EOP-004-4

Formal Comment Period Open through September 8, 2016
Ballot Pools Forming through August 23, 2016

Now Available

A 45-day formal comment period for **EOP-004-4 – Event Reporting**, is open through **8 p.m. Eastern, Thursday, September 8, 2016**.

Commenting
Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Tuesday, August 23, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps
Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 30 – September 8, 2016**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Sean Cavote (via email) or at (404) 446-9697.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-08 Emergency Operations | EOP-004-4
Comment Period Start Date:	7/25/2016
Comment Period End Date:	9/8/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-004-4 EOP-004-4 IN 1 ST 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 NBP IN 1 NB

There were 53 sets of responses, including comments from approximately 50 different people from approximately 47 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

2. Do you agree with the recommendation to retire EOP-004,-3 Requirement R3? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

5. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - EOP Project	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Karl Kohlrus	Prairie Power, Inc.	3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	RF
					Chris Bradley	Big Rivers Electric Corporation	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona's G&T Cooperatives	1	WECC
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC

					Nathan Bigbee	ERCOT	2	Texas RE
Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF
					Karla Jara	PSEG - Energy Resources and Trade LLC	6	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area	1,6	MRO

						Power Administration		
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
PPL - Louisville Gas and Electric Co.	Robert Tallman	3,5,6	RF,SERC	LG&E and KU Energy	Bob Tallman	LG&E and KU Energy	3,5,6	SERC
					Charlie Freibert	LG&E and KU Energy	3	SERC
					Dan Wilson	LG&E and KU Energy	5	SERC
					Linn Oelker	LG&E and KU	6	SERC

						Energy		
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC

					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Don Schmit	Nebraska Public Power District	1,3,5	SPP RE
					James Nail	Independence Power & Light	3	SPP RE
					Michelle Corley	Cleco Corporation	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
Santee Cooper	Shawn Abrams	1		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Chris Wagner	Santee Cooper	1	SERC
					Stony Martin	Santee Cooper	1	SERC
					Chris Jimenez	Santee Cooper	1	SERC
					Glenn Stephens	Santee Cooper	1	SERC
					Diana Scott	Santee Cooper	1	SERC

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
NPPD recommends that the parenthetical text be updated to read: (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday**, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day**	
Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
For all questions the California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
The NSRF agrees with R1 and recommends a small change to R2. Recommend the follow additions to clarify that all entities experience "holidays" and those holidays should be included in the same manner as weekends. *Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of*	

recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday). The NSRF recommend that the parenthetical text be updated to read (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).

R2 Recommendation:

NPPD recommends that the parenthetical text be updated to read: (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday**, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.**

Rationale:

Events occurring on a Friday after 12:00 p.m. local time or within the same timing prior to a holiday would have to be reported that day. This does not allow enough time for evaluation and development of a report. In addition, consideration for reporting should also be given to holidays observed by the reporting entity.

Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

We agree with R1 and recommend a small addition to R2 to clarify that all entities experience “holidays” and those holidays may vary from entity to entity and should be included in the same manner as weekends. Suggested change to R2:

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entities’ next business day if the event occurs on a holiday or weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday local time). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the Responsible Entities’ next business day.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with R1 and recommend a small addition to R2 to clarify that all entities experience “holidays” and those holidays may vary from entity to entity and should be included in the same manner as weekends. Suggested change to R2:

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entities’ next business day if the event occurs on a holiday or weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday local time). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the Responsible Entities’ next business day.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE noticed Requirement R1 has the term “event reporting Operating Plan”, while Requirement R2 just says “Operating Plan”. Texas RE recommends adding the descriptor “event reporting” to Requirement R2 or removing it from R1 for consistency. The Requirement R1 VSLs do not include the descriptor except part of the Severe VSL. It appears that the event report should be a written report yet the VSLs for R2 consider a written

or verral event report. Texas RE noticed there is no requirement specifically indicating how events should be reported. Additionally, the VSLs indicate that a verbal report is acceptable. Since an event reporting form exists, Texas RE recommends the requirements specify the form in Attachment 2 be used for event reporting. The language in R2 incorporates the various changes within Attachment 1 by reference. As such, Texas RE's concerns regarding changes to Attachment 1 should be incorporated herein by reference.

Likes 0	
Dislikes 0	

Response

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project

Answer	No
Document Name	

Comment

The proposed changes to R2 are not substantive, which raises the question for the need to revise R2 at all. R2 states, "Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type…" This change does not propose any new action, as this is already listed in the Operating Plan. The revision to R2 is not needed.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

We request that the SDT confirm that the time clock starts in R2 upon 'recognition' of the event threshold rather than when the event occurred. There may be analysis of the event that later reveals that the threshold was crossed.

We suggest the following clarification to M2 in order to provide additional clarity that this requirement does not supersede any OE-417 reporting timelines. This requirement may allow additional time to report to NERC, but OE-417 requirements may still require reporting within a shorter timeframe.

Perhaps all that is needed is the following addition to the proposed M2:

M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted **to NERC** within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	No
Document Name	
Comment	

Kansas City Power and Light Company endorses and incorporates by reference Nebraska Public Power District’s response in opposition to Question 1.

In addition, we offer the following:

Capitalization: The words “control center” are used in the Rationale. Since the term is an approved NERC Glossary Term, we suggest it be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of “control center.”

Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

SRP recommends adjusting the language in R2 to clarify the requirement is referring to events “recognized” during a weekend as opposed to events “occurring” on a weekend.

As the current language stands, an event occurring at 7:00 AM on a Monday would have to be reported by the end of the same business day.

Likes 0	

Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SMUD/BANC agrees with the intention that the drafting team is heading with the EOP-004 Draft 4 posting. However, we suggest the Standard Drafting Team consider a minor change to the language in Requirement R2 to address reportable events that occur during holiday periods. We suggest reportable events occurring during holiday be handled in a similar manner that the 'weekend' reportable event schedule that is reported events over the holiday would be reported on next business day.	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Hydro One Networks is satisfied with the clarification in language in R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	

Hydro One Networks is satisfied with the clarification in language in R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	Yes
Document Name	
Comment	

We recommend removing the words "but is not limited to" in M1. This language is no used in R1 and adds no value. It could be interpreted that the Operating Plan must not be limited to the protocols and therefore create an obligation that is not intended to include other elements which are no defined in R1.

M1 should read:

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.

Drafting team should consider adding more specificity to the "other organizations" from Requirement 1. As written this is a potential compliance issue if the Registered Entity elects not to include any "other organizations" such as the Regional Entity or the RC. It is unclear if adding other organizations is voluntary or specifically required by the Requirement.

The examples should be removed unless they are required. These would be more appropriate in the measure, not the language of the requirement. If it is not removed, then the Drafting team should consider removing any entities from the example section not specifically related to the ERO Enterprise. For example, the inclusion of law enforcement is unclear. There are many events listed in Attachment 1 in which law enforcement would not need to be notified. Conversely, there are many types of situations that should be reported to law enforcement that are not considered in Attachment 1. Further, all entities that need to be notified of conditions in real-time should be removed from consideration, such as the RC. Notifications to these types of entities is already required within other standards (changes in operating conditions or capabilities in IRO and TOP standards). As this is in the "Operation Planning" time horizon and will be used to inform the industry as needed and support events analysis the only entities that should be listed in this standard is NERC and the Applicable Regional Entity.

In R1 and R2 all provisions related to weekends should be removed. The standard requires notification within 24 hours of recognition. If an event occurs on the weekend at an unstaffed location and is not recognized until Monday morning, the entity should still have the 24-hour time frame to complete the notification. As the reporting obligation time frame begins upon "…recognition of meeting an event type threshold for reporting…" there is no need to have a weekend provision. This also removes an ambiguity in R2 which does not have the provision for "recognition of meeting an event type…" for events on the weekend. As written, weekend occurring events must be reported by the end of business Monday regardless of recognizing it as an event identified in Attachment 1.

M2 should be revised to remove the implication that EOP-004-4 Attachment 2 or the DOE-OE-417 forms are the only acceptable forms of evidence. As these forms are not specifically listed in the requirement language there should be flexibility written into the measure allowing for other evidence of event reporting. Conversely, the Attachment 2 and OE-417 forms should be listed in the R2 if they are required to demonstrate compliance.

Likes 0	
Dislikes 0	

Response

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	Yes
Document Name	

Comment

Hydro One Networks Inc. is satisfied with the clarification provided and language in R1 and R2.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	Yes
Document Name	

Comment	
NV Energy agrees with R1 and recommends a minor change to R2 to consider holidays and recommends that for any holiday, the event report shall be submitted no later than then the end of the next business day. Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.	
Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Thomas - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the recommendation to retire EOP-004,-3 Requirement R3? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned that contact list will not be updated if there is no requirement to do so. By removing the obligation, entities may learn of an outdated contact when the contact is needed.

Likes 0	
Dislikes 0	

Response

Jaclyn Massey - Entergy - Entergy Services, Inc. - 5

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Erika Doot - U.S. Bureau of Reclamation - 5

Answer	Yes
Document Name	

Comment

The Bureau of Reclamation agrees with the drafting team's proposal to retire EOP-004 Requirement R3 because it is administrative in nature.

Likes 0	
Dislikes 0	

Response

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project	
Answer	Yes
Document Name	
Comment	
We agree with the retirement of Requirement R3, because there are administrative aspects to this requirement.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
Hydro One Networks Inc. is satisfied with the removal of R3.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	

Answer	Yes
Document Name	
Comment	

Hydro One Networks is satisfied with the removal of R3.

Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling

Answer	Yes
Document Name	
Comment	

Hydro One Networks is satisfied with the removal of R3.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	

While we agree with the proposed retirement of R3, we believe the RC should gather and provide (perhaps on their website) contact information for applicable RCs, REs, and TOs within their footprint to ensure that reports are provided to appropriate entities.

Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Thomas - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	
No suggested changes to the text that has been modified. In addition, suspicious activity must be defined.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We do not agree with the following changes:

1. **For the Event Type "Public appeal for load reduction": It is unclear what "maintain the continuity of the BES" really means. By "continuity", does it mean "integrity of the BES" or "continuity of supply"? This needs to be revised to be more specific and to improve clarity.**

2. **Assigning the TOP to be the responsible entity for reporting system wide voltage reduction**

Voltage reduction is intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend changing it to the BA. Also, similar to the comment above, it is unclear what "maintain the continuity of the BES" really means. By "continuity", does it mean "integrity" or "continuity of supply"? Either way, we do not see the value added or the necessity of the having this qualifier. We suggest to revise the Event Type to "System wide voltage reduction" or where a qualifier is deemed to add value, change it to "System wide voltage reduction to maintain load supply" or "to meet system demand".

3. **The Event Type "Firm load shedding resulting from a BES Emergency": the basis for the reporting threshold, i.e., 100 MW, etc. has**

not been provided. We would appreciate the SDT providing the technical basis/justification other than just because it existed before.

Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Dislikes 0	

Response

Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy

Answer	No
Document Name	

Comment

LG&E and KU Energy ("LG&E/KU") appreciates the opportunity to submit this comment for the Standard Drafting Team's consideration.

The reportable event type "Complete loss of Interpersonal Communication capability at a BES control center" has a threshold for reporting of "Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more." LG&E/KU proposes the event type be rewritten as "Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability at a BES control center". Furthermore, LG&E/KU proposes changing the threshold for reporting to read "Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability affecting a staffed BES control center for 30 continuous minutes or more."

Likes 1	OGE Energy - Oklahoma Gas and Electric Co., NA - Not Applicable, Tay Sing
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy appreciates the SDT's time and effort towards the improvement of the Event Reporting Standard and is agreeable to the proposed revisions to R1 and R2, and the retirement of R3. However, CenterPoint Energy believes that proposed revisions to Attachment 1 may not be completely clear to the industry and would like the SDT to consider the following:

The proposed revisions regarding the "public appeal for load reduction" Event Type appears to expand the threshold to include events beyond the NERC defined "BES Emergency" which is defined as: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System". CenterPoint Energy believes removing BES Emergency as a threshold and adding the phrase "continuity of the BES" is ambiguous. The Company appreciates the SDT aligning the language with DOE OE-417; however, DOE OE-417 instructions state that the report should be made only if an appeal is made during emergency conditions. Therefore CenterPoint Energy recommends the reporting threshold read, "BES Emergency requiring public appeal for load reduction to maintain continuity of the BES.

CenterPoint Energy also has a similar concern regarding the use of “continuity of the BES” for the proposed changes to the “System-wide voltage reduction…” event type. CenterPoint Energy believes that for consistency the Event type should read, “System-wide voltage reduction” and the threshold for reporting should read, “BES Emergency requiring system wide voltage reduction of 3% or more to maintain continuity of the BES.”

In the “BES Emergency requiring manual Firm load shedding” event type, removing the word “manual” potentially broadens the scope and may also include automatic firm load shed, which would incorporate UFLS and UVLS. With these revisions and with the deletion of the Event Type, “BES Emergency resulting in automatic firm load shedding”; is it the SDT’s intent to consolidate all firm load shedding into one event type regardless of whether it is performed automatically or manually? If this is so, are UVLS, UFLS , and RASs still considered as automatic firm load shedding as it would be considered in the revised “Firm load shedding resulting from a BES Emergency” Event Type?

CenterPoint Energy considers manual and automatic Firm load shedding to be “controlled” actions that are deliberate and by design, regardless of whether initiated by a System Operator or relay scheme that is triggered by a threshold being met. CenterPoint Energy recommends the “Threshold for Reporting” to read, “Controlled Firm load shedding, manual or automatic via an Undervoltage Load Shedding Program, under-frequency load shedding scheme, or by Remedial Action Scheme ≥ 100 MW.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5

Answer	No
Document Name	

Comment

First Recommendation: Delete the Transmission loss Event Type in Attachment 1.

Rationale:

1. The EOP-004 reporting should stay focused on larger events, such as the criteria under Generation loss (Total generation loss, within one minute, of greater than or equal to 2,000 MW for entities in the Eastern or Western interconnection). Three transmission elements provide a very low threshold identified in the Transmission loss section. These low impact events can be better handled through the NERC Event Analysis Program (EAP). The EAP has matured over time and now provides an excellent means to identify and document lessons learned from events.
2. The Event Analysis Program (EAP) is providing a back door for changes to the EOP-004 reporting process without changes to the EOP-004 reporting process being vetted through the Standards Development Process. Case in point, an entity recently filed an EAP notification for a slow breaker trip impacting three or more elements and in which all related relaying operated by design. The Regional Entity directed that the entity report under the EOP-004 reporting process. The EOP-004 Event Type clearly states three elements “contrary to design”. With continual

changes to the EAP and the dissimilarities in the two processes (EAP/EOP) these changes and differences are clearly leading to confusion for both the reporting entity and the Regional Entities.

3. The EAP is a robust and documented process that provides for interaction between the Regional Entity and the reporting entity in the classification of Event types. All reporting for NERC/FERC classification of Events can be handled under the EAP process for this Event type, along with the current reporting under TADS and GADS. Lessons Learned are developed through this EAP process for the industry to learn from these events. The Transmission loss Event type under the EOP provides no further benefit and, in fact, as noted creates confusion on application for reporting.

4. The definition of BES Element in this EOP-004 Event type (Transmission loss) includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event type and also leads to confusion as to the element count for three elements contrary to design. In addition, the Event Analysis Program (EAP) uses the definition of “BES Facility” in its application and not “BES Element” as used in the EOP Event type which leads to further confusion in evaluating reporting during an Event.

Second Recommendation: Add “Alternate Interpersonal Communication” to the Event type “Complete loss of Interpersonal Communication capability at a BES control center.

Rationale: Prior to the implementation of COM-001-2, an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provides for actions to be taken for the loss of Interpersonal Communications. We suggest that the “Complete” loss of voice communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event.

Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

It may be beneficial to provide general guidance (perhaps at the very top of the table), exactly which entity has the reporting responsibility. If an entity directs another entity to perform an action, the entity issuing the directive would have the reporting responsibility. In all other instances, the responsible party would be the entity who actually experienced the event. For example, such clarity might be beneficial in cases where the RC is the TOP.

Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	

First Recommendation: Delete the Transmission loss Event Type in Attachment 1.

Rationale:

1. The EOP-004 reporting should stay focused on larger events, such as the criteria under Generation loss (Total generation loss, within one minute, of greater than or equal to 2,000 MW for entities in the Eastern or Western interconnection). Three transmission elements provide a very low threshold identified in the Transmission loss section. These low impact events can be better handled through the NERC Event Analysis Program (EAP). The EAP has matured over time and now provides an excellent means to identify and document lessons learned from events.

2. The Event Analysis Program (EAP) is providing a back door for changes to the EOP-004 reporting process without changes to the EOP-004 reporting process being vetted through the Standards Development Process. Case in point, an entity recently filed an EAP notification for a slow breaker trip impacting three or more elements and in which all related relaying operated by design. The Regional Entity directed that the entity report under the EOP-004 reporting process. The EOP-004 Event Type clearly states three elements “contrary to design”. With continual changes to the EAP and the dissimilarities in the two processes (EAP/EOP) these changes and differences are clearly leading to confusion for both the reporting entity and the Regional Entities.

3. The EAP is a robust and documented process that provides for interaction between the Regional Entity and the reporting entity in the classification of Event types. All reporting for NERC/FERC classification of Events can be handled under the EAP process for this Event type, along with the current reporting under TADS and GADS. Lessons Learned are developed through this EAP process for the industry to learn from these events. The Transmission loss Event type under the EOP provides no further benefit and, in fact, as noted creates confusion on application for reporting.

4. The definition of BES Element in this EOP-004 Event type (Transmission loss) includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event type and also leads to confusion as to the element count for three elements contrary to design. In addition, the Event Analysis Program (EAP) uses the definition of “BES Facility” in its application and not “BES Element” as used in the EOP Event type which leads to further confusion in evaluating reporting during an Event.

Second Recommendation: Add “Alternate Interpersonal Communication” to the Event type “Complete loss of Interpersonal Communication capability at a BES control center.

Rationale: Prior to the implementation of COM-001-2, an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provides for actions to be taken for the loss of Interpersonal Communications. We suggest that the “Complete” loss of voice communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event.

Suggested Change:

Complete loss of Interpersonal Communication and Alternate Interpersonal Communication capability at a BES control center.

Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3

Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We request that the proposed revision to the category for 'Complete Loss of Interpersonal Communication Capability at a BES control center' be clarified to state that the threshold requires loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities. We believe that is the intent of the threshold which is consistent with the EAP. However, since both Interpersonal Communication and Alternative Interpersonal Communication are defined terms it is unclear from the posted Attachment 1 language whether this is the intention of the SDT. Accordingly, we propose rewording the reporting threshold to:

Complete loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities at a BES control center.

In addition, the category for a 'Complete loss of off-site power to a nuclear generating plant (grid supply)' could be better aligned with the EAP. The EAP refers to a 'LOOP event' which could be referenced here to provide consistency. Alternatively, the EAP could be updated to better align with the proposed revision. In addition, the current use of the phrase "complete loss of off-site power" in the Event Type as well as the Threshold for Reporting is problematic for the TO, TOP to be the Entity Responsible for Reporting. Loss of off-site power (LOOP) is a well-defined term in the nuclear industry and is heavily dependent on in-plant alignments and operating conditions as well as transmission configuration which the TO/TOP has only has a partial awareness of. Nuclear Plant Interface Requirements are intended to ensure that the NPGO has all of the information necessary to determine the operability of off-site power per the plant license agreement. Should the existing wording of the Event Type and Threshold for Reporting be kept the Entity with Reporting Responsibility should be changed to the Nuclear Plant Generator Operator rather than the TO/TOP since the TO/TOP does not have the knowledge nor expertise to determine when a loss of off-site power condition exists. Similar to NERC accepting the DOE OE-417 report there is a higher degree of efficiencies and effectiveness of reporting for the NPGO since loss of offsite power events are reportable to other regulators under plant licensing requirements. Different Functional Entities independently reporting of the same event to different regulators creates a significant opportunity for confusing or even possibly conflicting information.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We request that the proposed revision to the category for 'Complete Loss of Interpersonal Communication Capability at a BES control center' be clarified to state that the threshold requires loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities. We believe that is the intent of the threshold which is consistent with the EAP. However, since both Interpersonal Communication and Alternative

Interpersonal Communication are defined terms it is unclear from the posted Attachment 1 language whether this is the intention of the SDT. Accordingly, we propose rewording the reporting threshold to:

Complete loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities at a BES control center.

In addition, the category for a 'Complete loss of off-site power to a nuclear generating plant (grid supply)' could be better aligned with the EAP. The EAP refers to a 'LOOP event' which could be referenced here to provide consistency. Alternatively, the EAP could be updated to better align with the proposed revision. In addition, the current use of the phrase "complete loss of off-site power" in the Event Type as well as the Threshold for Reporting is problematic for the TO, TOP to be the Entity Responsible for Reporting. Loss of off-site power (LOOP) is a well-defined term in the nuclear industry and is heavily dependent on in-plant alignments and operating conditions as well as transmission configuration which the TO/TOP has only has a partial awareness of. Nuclear Plant Interface Requirements are intended to ensure that the NPGO has all of the information necessary to determine the operability of off-site power per the plant license agreement. Should the existing wording of the Event Type and Threshold for Reporting be kept the Entity with Reporting Responsibility should be changed to the Nuclear Plant Generator Operator rather than the TO/TOP since the TO/TOP does not have the knowledge nor expertise to determine when a loss of off-site power condition exists. Similar to NERC accepting the DOE OE-417 report there is a higher degree of efficiencies and effectiveness of reporting for the NPGO since loss of offsite power events are reportable to other regulators under plant licensing requirements. Different Functional Entities independently reporting of the same event to different regulators creates a significant opportunity for confusing or even possibly conflicting information.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned that the following proposed changes to EOP-004 Reportable Events could lead to gaps in reliability and confusion among registered entities.

- Texas RE is concerned that the proposed revisions eliminate the requirement that Reliability Coordinators (RC) submit event reports in connection with situations in which there are operations outside the IROL for a time greater than the IROL's Tv (typically 30 minutes). The management of IROLs is a key aspect of a RC's constraint management activities. In particular, situations in which an IROL is exceeded for a period sufficient to trigger an unacceptable risk to the interconnection or other Reliability Coordinator Areas represents a significant systemic event. While such an exceedance may be investigated in the compliance or enforcement process, there is necessarily a delay in these activities. The contemporaneous reporting obligations serve to ensure that the NERC regions have immediate knowledge that a significant risk of a cascading outage has occurred, permitting the region or regions to begin steps to identify the root cause and develop appropriate mitigation. Because such awareness appears critical to the core reliability functions performed within the NERC regions, Texas RE cautions against eliminating this requirement. At a minimum, Texas RE requests that the SDT provide a rationale for why the IROL Tv event reporting requirement should be removed, including whether the SDT believes that the event reporting aspects of EOP-004 are adequately addressed in other standards.

- Texas RE has noted that the SDT proposes to eliminate the event reporting obligations of certain NERC functions. For example, the proposed revisions would no longer require DPs to report automatic firm load shedding resulting from a BES Emergency. Similarly, the proposed revisions no longer require GOPs to report generation loss in excess of 1000 MW in the ERCOT region. Texas RE requests that the SDT provide the rationale for narrowing these event reporting obligations. If the SDT believes that such reporting obligations are duplicative, Texas RE would also request evidence supporting that assertion.

- Based on its own engagement with registered entities in the ERCOT region, Texas RE also believes there is some confusion regarding event reporting terms. In particular, the distinction between "Firm load shedding resulting from a BES Emergency" and "Uncontrolled loss of firm load resulting from a BES Emergency" appears unclear. "Firm load shedding" could be read to refer solely to intended load shedding events (either manual or automatic). If so, the SDT may wish to consider replacing the term "uncontrolled" with "unintended" to better capture the distinction between intentional and unintentional firm load shedding.

- It appears the "Public appeal" for load reduction ignores localized situations that may still require a localized public appeal that may be better facilitated by a TOP or DP (and actually recognized later in the loss of load issues). Texas RE requests rationale for the change.

- Texas RE noticed the event type "Voltage deviation on a Facility" did not include the GOP. "Voltage deviation on a Facility" could occur at a GOP site as well and should be recognized since the GOP is to maintain that voltage. Texas RE inquires as to why was the GOP is not included.

- It appears the eliminated event type "BES Emergency resulting in automatic firm load shedding" is intended to be captured in the event type "Firm load shedding resulting from a BES Emergency", however the same functions are not captured. Texas RE requests clarification and rationale from the SDT regarding this change. Texas RE is concerned the removal of reporting UVLS/UFLS/RAS load shedding reduces situational awareness for the RC and other functional entities.

- Texas RE requests rationale for the event type "Complete loss of Interpersonal Communication capability at a BES control center". Texas RE is concerned the term "BES control center" is undefined and might cause confusion. Additionally, it ignores the DP and GOP responsibilities for having Interpersonal Communication.

- Texas RE inquires as to why a GOP Control Center is not considered in any of the event thresholds (and why is the undefined term "BES control center" limited to BA, RC, and TOP functions?)

- For the event type "Firm load shedding resulting from a BES Emergency", Texas RE inquires if the SDT intends for an event to be reported in a case where a RAS intentionally sheds load in response to a contingency for which the RAS was designed?

- For the event type "Transmission loss", Texas RE suggests adding the RC to the reporting responsibility. This event type implies that the three or more elements that are lost are within a single TOP boundary. We have numerous examples of events affecting multiple entities and elements outside of a single TOP boundary.

- To maintain alignment between EOP-004 and the NERC Events Analysis Process, we suggest adding an event type for reporting the failure or misoperation of a RAS.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy provides comment on the following Event Types:

Public Appeal for load reduction: The proposed language for this event includes the phrase *"to maintain continuity of the BES"*. While we agree with the intent of the revisions, we disagree with the verbiage used. We do not believe that maintaining continuity of the BES is a concept that is widely understood by the industry, and suggest that using "to maintain reliability of the BES" would be more widely understood and accepted by the industry.

System-wide voltage reduction to maintain the continuity of the BES: Please see our comment above regarding the use of the phrase "*to maintain continuity of the BES*". Also, we request further explanation from the drafting team on singling out the TOP as the entity with reporting responsibility. This concept may be particularly troublesome for vertically integrated entities. Entities that are integrated BA/TOP, either the BA or TOP can initiate voltage reduction. Lastly, the voltage reduction actually takes place on the distribution system, so we request further clarification of the singling out of the TOP only for this event, and request the drafting team consider adding the BA as an entity responsible for reporting for this event type.

Firm load shedding resulting from a BES Emergency: Some ambiguity may exist with having the multiple entities listed as being responsible for reporting per event. For example, a BES Emergency arises wherein an RC directs a BA/TOP to shed firm load. Following the language found in Attachment 1 of this standard, it is unclear whether the RC should file the event report, the BA/TOP would file the event report, or both. Is it the drafting team's intent to have all or both functions submit an event report. If the intent is just for one report per event type to be filed, some language needs to be added affording entities the opportunity to discuss and decide which function will submit the event report. In the Guidelines and Technical Basis section of this standard, there is a section for Multiple Reports for a Single Organization. Perhaps a section could be added regarding reports involving multiple functions that stems from one event, and who is the responsible party for the reporting.

Uncontrolled loss of Firm load resulting from a BES Emergency: We requests further clarification from the drafting team on the addition of the term "Uncontrolled", and whether or not using the term now negates the use of the DOE form for NERC reporting. This may result in an entity having to fill out two separate reports. Was this the drafting team's intent? Also, is the term "Uncontrolled" referring to Operator controlled? Please clarify.

Transmission Loss: There appears to be a disconnect between the definition of BES Element in the NERC standards process, and the NERC Events Analysis process. We feel that a great deal of confusion exists on the reporting for this type of event. We request the drafting team to consider revising the associated language of this event type to help narrow down the intended scope of this event. As of now, the language is so broad that entities spend a considerable amount of time creating reports for this event type, and would greatly benefit by narrowing the scope or revising the language to better demonstrate intended expectations.

Complete loss of Interpersonal Communication capability at a BES control center: Duke Energy questions the necessity of reporting for this event type. Currently, there is already a NERC standards regarding Interpersonal Communication and actions that must be taken if the capability is lost. Also, an entity is already required to have Alternative Interpersonal Communication as well. Does this reporting of this event type include an event where Alternative Interpersonal Communication capabilities are also lost? The standard already requires that an entity notify neighboring entities of the loss of communications, and now it appears that with this revision, an entity will need to file an event report to NERC regarding the loss, even if the loss has been mitigated. We feel that this reporting requirement is redundant with COM-001 where notifications around the loss of communications is already required.

Complete loss of monitoring or control capability at a BES control center: Duke Energy requests clarification on the addition of the term "staffed" under Threshold for Reporting for the event type, Complete loss of Interpersonal Communication capability at a BES control center, but the term was not used in the Threshold for Reporting for this event type. The drafting team may have intended to include the term "staffed" to the language of this event but may have overlooked it. If the omission was intentional, please clarify why it was not included for this event type.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra

Answer	No
Document Name	

Comment

There are numerous “its” references in the description of the Event Type, but not clear who this is in reference to? Is it intended to imply that “its” is in referencing the Functional Entity that’s identified in the respective row of the second column – “Entity with Reporting Responsibility”? Will these always match up? Are there instances where the reporting entity and the owning entity are different? For example, in ISO-NE the RC submits all the reports. This may need some clarity.

GOP should be removed from the “Entity with Reporting Responsibility” for the “Physical Threats to its Facility” event type and added to the “Physical threats to its BES control center” event type. Facility is defined as – “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” and thus does not capture a GOP control center. So in order for these critical assets to be captured in the physical threats reporting requirements of the Attachment 1, GOP must be added to the “Physical threats to its BES control center” event type.

Same as comment 2 for “Physical threats to its Facility” event type.

For the “Public appeal for load reduction” event type, TOP should be added to the “Entity with Reporting Responsibility”. EOP-001-2.1b, R4 – “R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.”

Attachment 1-EOP-001, Elements for Consideration in Development of Emergency Plans

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.

“System-wide voltage reduction to maintain the continuity of the BES” event type

a. BAs and RCs can potentially implement a system-wide VR due to capacity and energy emergencies in accordance with their emergency plans, as required under EOP-002-3.1 - Capacity and Energy Emergencies, so we don’t see why these functions are being excluded from the reporting requirement.

b. should be better aligned with the EAP event category 1d –

Recommend –

Threshold for reporting – no change

Event Type –System-wide voltage reduction in accordance with the entity’s emergency plan resulting from a BES Emergency.

c. Threshold requirement of “system wide” should be clarified to specify whose system it is. This is a similar ambiguity as the one being requested for clarity in item 1 above. Are we implying that it’s the TOP’s (Entity withy Reporting Responsibility) system? Are there instances when the requesting entity is a BA/RC requesting a voltage reduction for a particular TOP? In such cases, would it be reportable and who would be the Entity with reporting responsibility. Is the intent to require reporting of such events? Should BAs and RCs be added to the Reporting Entities?

EOP-002-3_1 R6 -

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

For “Transmission Loss” event type please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as category 1.a. in the EAP).

For the transmission loss category: The term “contrary to design” should be better defined. In October 2015 an addendum for Category 1a Events was created for the Event Analysis Process. This addendum indicates that breaker failure operations are not as intended. Is the intent to mimic the EA Process? Also, the term “excluding successful automatic reclosing” does not align with the EA Process language for Transmission loss.

NERC Definition of Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Definition of Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.

The intent is to capture the outage of three or more Facilities (each Facility can be comprised of two or more Elements), not the underlying Elements.

Loss of firm load (BA, TOP, DP) - Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year’s demand ≥ 3,000 OR ≥ 200 MW for all other entities.

Recommend adding the following qualifiers:

· This does not include the loss of load when it is caused by “customer actions to protect their systems” and not the utility (e.g. customer’s relays settings to swap over to own generation set higher than the utility’s UFLS/UVLS settings).

· This excludes radially connected industrial load loss. Design and level of reliability was approved and accepted.

Suggest replacing the “uncontrolled” in the Event Type with the “unintended” language (similar to the EAP category). “Uncontrolled” implies or may get interpreted as a cascading type of an event, limiting the reporting requirement to only those types of events.

Unplanned BES control center evacuation (RC, BA, TOP) - Unplanned evacuation from BES control center facility for 30 continuous minutes or more.

Add GOP to the Entity with Reporting Responsibility. Similar reasons specified in the Attachment 1, Item 2 above. Additionally, if the GOP BES control centers are subject to consideration and classification as High, Medium and Low impact facilities in accordance with the CIP-002 evaluation, they should be considered in this reporting criteria, at least for the GOP’s Control Centers that meet the reporting threshold for “Generation Loss” event type (≥ 2,000 MW for entities in the Eastern, or Western, or Quebec Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection); or, as an alternative, High Impact (as classified under the CIP-002) control centers – CIP-002-5.1 - Attachment 1 Impact Rating

Criteria

The criteria defined in Attachment 1 do not constitute stand ... he level of impact and are
referenced by requirements.

1. High Impact Rating (H) Each BES Cyber System used by and located at any of the following: 1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

Complete loss of monitoring capability (RC, BA, TOP)- Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or {more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.}

Add the word “staffed” to the threshold column for “Complete loss of monitoring or control at a BES control center” so that it is consistent with the event Type above it which states: Complete loss of Interpersonal Communication capability affecting a “staffed” BES control center for 30 continuous minutes or more.

The BA should also be identified as an “Entity with Reporting Responsibility” for System-wide voltage reduction since according to the functional model the BA may request the TOP or directly address a DP to reduce voltage to ensure balance within its BA area.

Agree with the changes eliminating the bracketed statement as it is not indicative of a complete loss of monitoring capability and has caused confusion throughout the industry.

Likes 0	
Dislikes 0	

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	No
Document Name	

Comment

We do not agree with the elimination of “BES Emergency requiring” for a public appeal for load reduction. During periods of very hot weather or other high load situations, even though there is not a BES emergency there are public appeals to exercise conservation to ensure sufficient resources on a regional or statewide basis. Reporting to NERC of public appeals for load reduction or conservation should only be required for BES emergency conditions as written in the current version.

Likes 0	

Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments of the ISO RTO Council (IRC) Standards Review Committee (SRC). In addition, ERCOT provides the additional comment below.

a. We ask the SDT to consider setting the reporting criteria for the "Generation loss" event type in ERCOT at 1,400 MW rather than 1,000 MW. This would align the current reportable MW threshold for ERCOT with the NERC Event Analysis process threshold for a Category 3 event.[1] As currently written, entities in the Eastern Interconnection are required to report in the event of a Category 3 event with a loss of generation of 2,000 MW or more, while ERCOT would be required to report in the event of a Category 1 event with a loss of generation of 1,000 MW. Setting the reporting threshold at 1,400 MW for generation loss in ERCOT would establish equitable criteria for reporting in the ERCOT interconnection.

[1] http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_EAP_V3_final.pdf

Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

We do not agree with the following changes:

a. For the Event Type "Public appeal for load reduction": It is unclear what "maintain the continuity of the BES" means. Does "continuity" mean "integrity of the BES" or something else? This needs to be revised to be more specific and to improve clarity.

b. The phrase "Public appeal for load reduction to maintain continuity of the BES" could also unreasonably expand the number of required reporting instances. Public appeals are made in many different types of situations. Reliability Coordinators often make appeals when an emergency is only a possibility and not a likelihood. In many of these cases, the risk of an emergency condition is somewhat lower and should not rise to the level of concern to justify official event reporting. SRC therefore recommends that the SDT retain the defined term "BES Emergency" and use the phrase "Public appeal for load reduction in a BES Emergency to maintain integrity of the BES."

c. The SRC also disagrees with assigning the TOP the responsibility for reporting system wide voltage reduction. Voltage reduction is

intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend making the BA the responsible entity. Further, we don't agree with making every public appeal for demand reduction a reportable event. The redline removes the words "BES Emergency requiring…" and we believe that the words should remain so that only voltage reduction associated with BES Emergencies are reportable. " Also, similar to the comment above, it is unclear what "maintain the continuity of the BES" means. We suggest to revise the Event Type to "Voltage reduction" or where a qualifier is deemed to add value, change it to "Voltage reduction to meet system demand".

d. For consistency with comment (b) above "Public Appeal" should remain under the "BES Emergency" heading.

e. Having proposed the above, the SRC suggests that Public Appeal be removed from the list of Events to be reported since public appeal by its nature require the involvement of media. This is often done in advance of real time because of the required effort and coordination with media. Therefore, public appeal is more a cautionary action driven by anticipated conditions, and not actual conditions in real time. Given the nature of the appeal and the involvement of the media, there is sufficient information provided to NERC and the concerned government agencies, making a separate report is thus redundant.

f. The Event Type "Firm load shedding resulting from a BES Emergency": the basis for the reporting threshold, i.e., 100 MW, etc. has not been provided. We would appreciate the SDT providing the technical basis for this threshold.

g. In Attachment 1, the event "Unplanned BES control center evacuation" applies to RC, BA, and TOP. If the evacuated control center belongs to a TOP, the TOP should have the obligation to report this, and not the RC or BA, which could be one reading of this. Consistent with the SDT's use of the word "its" for the second, third, and fourth events listed in Attachment 1 to signify that only the entity experiencing the event has the reporting responsibility, SRC recommends changing the event type description in this case to "Unplanned evacuation of its BES control center." Similarly, SRC recommends changing the next two event type descriptions to address this same issue, so that they read "Complete loss of Interpersonal Communication capability at its BES control center" and "Complete loss of monitoring or control capability at its BES control center."

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

NV Energy supports the comments made by MRO-NERC Standards Review Forum:

Suggestion: Delete or clarify the Transmission loss Event Type in Attachment 1.

Rationale: Conflicting Event Analysis Program guidance, NERC Glossary definitions, and dispersed generation combine to make this Event Type confusing and challenging to evaluate within reporting timelines, subject to minimal impact, and requiring TOP's to have greater visibility of generation resources than they possess.

Conflicting Guidance

Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design.

NERC Addendum for EAP Category 1a Events, footnote 2, page 2, explains “contrary to design”: “If a single line fault results in the faulted line tripping along with two other lines misoperating and tripping, that is three elements outaged due to a common disturbance, contrary to design. That would be a qualified event.” Likewise, page 3 states “Protection system misoperations are considered contrary to design.” We can therefore conclude that protection system operations that operate as designed are not misoperations and not contrary to design.

This is so obvious that it shouldn’t need to be pointed out here, except that the EAP Addendum contradicts this understanding of protection system operations with respect to breaker failures. In an attempt to collect circuit breaker failure data “through the EA process to facilitate identification of trends with regards to circuit breaker failures… facilities that are tripped due to breaker failure are counted as facilities outaged in determining categorization” regardless of whether that tripping is caused by the correct operation of protection systems. Examples 5 and 6 explicitly state that lines outaged by correct operation of protection systems are to be counted “since it was a breaker failure.”

While a guidance document can circumvent the plain meaning of “contrary to design” for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4 reliability standard. This results in differing criteria for evaluating which lost/outaged BES Elements/Facilities count towards the three-element threshold.

Includes Minimum Impact Losses

The NERC Glossary definitions of Elements and Facilities specifically list generators as examples. BES Elements and BES Facilities include BES generators. With the revision of the BES definition, Inclusion I4 defines each and all individual dispersed power producing resources as individual BES facilities once they aggregate to greater than 75 MVA and are connected at a voltage of 100 kV or above.

By definition, every outage, contrary to design, of three or more BES wind turbines or solar cells caused by a common disturbance must be reported as a Transmission loss event under EOP-004, even though the loss is labeled as Transmission, contains no transmission elements, and does not meet the threshold for reporting a generation loss.

Blurs Event Types

Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Generation loss has BA reporting loss of MW. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss. This blurs the line between Event Types, obligating the TOP to make determinations to file an Event Report each and every time 3 or more BES wind turbines or solar cells and/or a combination thereof with transmission elements that are lost contrary to design due to a common disturbance. The blurred event types and previously identified conflicting guidance is not conducive to a 24 hour reporting requirement.

TOP’s are unlikely to have this level of visibility into wind/solar farms, necessitating GOP’s to report the loss of these BES Elements to their TOP, so the TOP, as the Responsible Entity, can submit the report. The TOP should not have the responsibility of reporting event types for generator disturbances.

Suggested Remedy

Delete the Transmission loss Event Type from Attachment 1. Events can and should be analyzed under EAP. The EAP is the preferred method as there is collaboration between the reporting entity and the Regional Entity. The data is collected by the RE and NERC and can be analyzed appropriately and lessons learned developed.

Alternatively, clarify the Transmission loss Threshold for Reporting as follows:

“Unexpected loss within its area, contrary to design, of three or more BES Elements (transmission lines or transformers) caused by a common disturbance (excluding successful automatic reclosing, and as-designed protection system operations for the initiating disturbance).

By explicitly stating “BES transmission lines and transformers” we exclude generators as well as the Elements (circuit breakers, busses, and shunt and series devices) that the EAP Addendum says do not need to be included. Adding “as-designed protection system operations” as an exclusion reinforces and reiterates the limitation of losses to those “contrary to design.” The qualifier “for the initiating disturbance” prevents a TOP from claiming that lines tripping on zone 3 relaying for a slow or stuck breaker is operating “as-designed.”

Page 12 of 16 , Row 6

Prior to the implementation of COM-001-2 an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provided for actions to be taken for the loss of Interpersonal Communications. We suggest that the “Complete” loss of voice communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event.

Suggested Change:

Complete loss of Interpersonal Communication and Alternate Interpersonal Communication capability at a BES control center.

Likes 0	
Dislikes 0	

Response

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project

Answer	No
Document Name	

Comment

1. With regard to Attachment 1, the majority of our comments agree with the proposed changes. However, there are a few event categories that need to be clarified.
2. We disagree with the deviation from NERC Glossary Terms for the complete loss of monitoring or control capability at a BES control center. We recommend that the SDT choose the NERC-defined term “Control Center” instead of the current proposal as lower-case “control center.” The NERC glossary definition would meet the criteria because this event category applies to the RC, BA, and TOP.
3. We question the removal of the RC reporting IROL violations or SOL violations on WECC Major Transfer Paths. This is a risk to reliability and NERC should be notified with an event report.
4. We also question the assignment of the RC, BA, and TOP to have reporting responsibility for Firm load shedding (> 100 MW) resulting from a BES Emergency. We are not sure if this assignment of three functions provides clarity. Are there any additional benefits to reliability for having all three entities be required to report a single load shedding event? We would like the SDT to clarify if there is an option for applicable registered entities to receive credit for reporting if one of the entities involved in a load shedding event reports on their behalf. The ability to file a report for multiple entities that are party to a single load shedding event would alleviate the burden of having to submit multiple reports for a single event.
5. We question the assignment of the BA as being solely responsible for reporting public appeals for load reduction, because some BA Areas (such as MISO or SPP) are too large for the BA to initiate such appeals. We ask the SDT to consider assigning the task to the TOP.
6. We agree with the current proposal to remove the DP from being required to report any automatic firm load shedding (> 100 MW), as this is covered by the BA, RC, and TOP.
7. Finally, we agree with the SDT that assigning the TOP as solely responsible for reporting system-wide voltage reduction (of 3% or more) to maintain the continuity of the BES provides more clarity regarding the reporting responsibilities.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design; however with differing definitions. EAP defines “BES Facility” and EOP-004 defines “BES Element”.

EOP-004 reporting threshold for loss of three elements uses “BES Elements”. The BES definition includes generators, the EOP reporting for the unexpected loss is for the TOP. This is confusing on how to count elements and how the TOP is to get notification of loss of generator elements to report. Actually the TOP should not be required to do so. Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss.

In addition, we are finding that the application of the EAP definition/process is being applied to EOP-004 reporting. While an EAP guidance document can circumvent the plain meaning of “contrary to design” for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4 reliability standard. This results in differing criteria for evaluating which lost/outage BES Elements/Facilities count towards the three-element threshold and an application that ignores the Standards approval process in the NERC Rules of Procedure.

The EAP process has examples for application, provides for collaboration between the entity and the regional entity provides for categorization for the NERC/FERC process and eventual lessons learned. As noted, the EOP-004 reporting item is confusing (and not correct) by definition and by application. The EOP line item for Transmission Loss needs to be eliminated in favor of the better defined and applied EAP process.

We also request that the category for ‘Loss of Interpersonal Communication Capability’ be clarified to state that the threshold requires loss of both Primary and Alternative Interpersonal Communication Capability. We believe that is the intent of the threshold, but with the language now in COM-001-2 using ‘primary and Alternative Interpersonal Communication’, we believe the addition would make it as clear as possible. As currently stated, it requires an interpretation as to whether it means complete loss of ‘just’ Primary or both. Such as:

Complete loss of **both primary and Alternative** Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more.

The category for loss of offsite power to a nuclear generator could be better aligned with the EAP. The EAP refers to a ‘LOOP event’ which could be referenced here to provide consistency. We also recommend that the Nuclear Plant Generator Operator be the responsible entity for reporting instead of the TO or TOP.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	No
Document Name	
Comment	

Kansas City Power and Light Company endorses and incorporates by reference Nebraska Public Power District's response in opposition to Question 3.

In addition, we offer the following:

BES Emergency: There is inconsistent use of the NERC Glossary Term, "BES Emergency." We can only speculate as to the SDT's intent. For example, removing the term is basically removing the qualifier and expanding the applicability of the event. The opposite would be true, limiting the applicability, by including the term. We would be interested in understanding the SDT's intent for determining inclusion or exclusion of the term, BES Emergency.

Capitalization: As noted in our Question No. 1 comments, the words "control center" are used in Attachments. Since the term, "Control Center," is an approved NERC Glossary Term, we suggest it be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of "control center."

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AECI agrees with the revisions to Attachment 1. However, AECI requests the SDT to revise the term BES control center. Control Center is already defined in the NERC Glossary of Terms and should be used in lieu of BES control center throughout the attachment.

Likes 0	
Dislikes 0	

Response

Lynda Kupfer - Puget Sound Energy, Inc. - 5

Answer	No
Document Name	

Comment

I wasn't given the option to skip the survey and support another's response after voting negatively for EOP-004-4. Please accept this response. PSE supports IESO, OGE and LG&E comments.

We do not agree with the following changes:

1. **For the Event Type "Public appeal for load reduction": It is unclear what "maintain the continuity of the BES" really means. By**

“continuity”, does it mean “integrity of the BES” or “continuity of supply”? This needs to be revised to be more specific and to improve clarity.

2. **Assigning the TOP to be the responsible entity for reporting system wide voltage reduction**

Voltage reduction is intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend changing it to the BA. Also, similar to the comment above, it is unclear what “maintain the continuity of the BES” really means. By “continuity”, does it mean “integrity” or “continuity of supply”? Either way, we do not see the value added or the necessity of the having this qualifier. We suggest to revise the Event Type to “System wide voltage reduction” or where a qualifier is deemed to add value, change it to “System wide voltage reduction to maintain load supply” or “to meet system demand”.

3. **The Event Type “Firm load shedding resulting from a BES Emergency”: the basis for the reporting threshold, i.e., 100 MW, etc. has not been provided. We would appreciate the SDT providing the technical basis/justification other than just because it existed before.**

Leonard Kula, Independent Electricity System Operator, 2, 8/30/2016

LG&E and KU Energy (“LG&E/KU”) appreciates the opportunity to submit this comment for the Standard Drafting Team's consideration.

The reportable event type “Complete loss of Interpersonal Communication capability at a BES control center” has a threshold for reporting of “Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more.” LG&E/KU proposes the event type be rewritten as “Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability at a BES control center”. Furthermore, LG&E/KU proposes changing the threshold for reporting to read “Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability affecting a staffed BES control center for 30 continuous minutes or more.”

LG&E and KU Energy, Segment(s) 3, 5, 6, 5/26/2016

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Under Event Type “BES Emergency resulting in voltage deviation on a Facility” the threshold should be updated to include the word ‘exceeding’. The threshold should read ‘A voltage deviation exceeding +/- 10% of nominal voltage sustained for >/= 15 continuous minutes.”	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
In Attachment 1, the removal of the TOP as a responsible reporting Entity for "Damage or destruction of its Facility" and "Physical threats to its Facility" potentially causes concern. This could be problematic for facilities that are owned by one entity but operated by another. We request that the SDT have continued discussion around these types of scenarios and consider putting the TOP back in as a responsible Entity.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Event Type: Public appeal for load reduction: There may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend leaving the “Entity with Reporting Responsibility” as it currently reads: **Initiating entity is responsible for reporting.** (Attachment 1, Page 10, 4th Row) Event Type: Firm load shedding resulting from a BES Emergency: We recommend leaving the “Entity with Reporting Responsibility” as it currently reads: **Initiating entity is responsible for reporting.** (Attachment 1, Page 11, 1st Row) Event Type: Generation loss; We recommend the following statement for ”Threshold for Reporting:” **Reporting of generation loss would be used to report Forced Outages, not weather patterns or fuel source unavailability for these resources.** (Attachment 1, Page 12, 2nd Row)	

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

At times there may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend replacing "BA" with "Initiating BA or TOP."

The event types with multiple applicable entities such as, "Firm load shedding resulting from a BES Emergency", "Uncontrolled loss of firm load resulting from a BES Emergency", and "System separation (islanding)" will most likely have the same event reported multiple times if the BA, TOP or RC are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type, "Firm load shedding resulting from a BES Emergency" to "Initiating RC, BA, or TOP". We recommend changing the Entity with Reporting Responsibility for the Event Type, "Uncontrolled loss of firm load resulting from a BES Emergency" to just the BA. We recommend changing the Entity with Reporting Responsibility for the Event Type, "System separation (islanding)" to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.

For Event Type *Uncontrolled loss of firm load resulting from a BES Emergency,* the MW lost amount may be better representative of an impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.

For Event Type *Complete Loss of Interpersonal Communications capabilities at a BES control center*, consider also adding Alternative Communication Capabilities. This will differentiate an event from a COM standard requirement. On the Event Type include "staffed" to match wording in the Threshold section.

For Event Type *Unplanned BES control center evacuation*, revise to: 'Unplanned evacuation of its BES control center' to more specifically identify the control center the Functional Entity is required to report on. This also makes the wording similar to that in the Physical threat Event Type.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	Yes
Document Name	

Comment

Add the word 'staffed' to the threshold column for 'Complete loss of monitoring or control at a BES control center' so that it is consistent with the Event Type above it which states:

Complete loss of Interpersonal Communication capability affecting a **staffed** BES control center for 30 continuous minutes or more.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

Consider adding 'its' to unplanned evacuation of (its) BES control center for consistency.

Consider adding 'Alternate Interpersonal Communications' in addition to complete loss of Interpersonal Communications to add clarity.

Consider adding 'staffed' to both event type and threshold for loss of control center Interpersonal Communications (p.12 of 16) for consistency.

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	Project 2015-08_ 3.docx
Comment	

Suggestion: Delete or clarify the Transmission loss Event Type in Attachment 1.

Rationale: Conflicting Event Analysis Program guidance, NERC Glossary definitions, and dispersed generation combine to make this Event Type confusing and challenging to evaluate within reporting timelines, subject to minimal impact, and requiring TOP's to have greater visibility of generation resources than they possess.

Conflicting Guidance

Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design.

NERC Addendum for EAP Category 1a Events, footnote 2, page 2, explains "contrary to design": "If a single line fault results in the faulted line tripping along with two other lines misoperating and tripping, that is three elements outaged due to a common disturbance, contrary to design. That would be a qualified event." Likewise, page 3 states "Protection system misoperations are considered contrary to design." We can therefore conclude that protection system operations that operate as designed are not misoperations and not contrary to design.

This is so obvious that it shouldn't need to be pointed out here, except that the EAP Addendum contradicts this understanding of protection system operations with respect to breaker failures. In an attempt to collect circuit breaker failure data “through the EA process to facilitate identification of trends with regards to circuit breaker failures… facilities that are tripped due to breaker failure are counted as facilities outaged in determining categorization” regardless of whether that tripping is caused by the correct operation of protection systems. Examples 5 and 6 explicitly state that lines outaged by correct operation of protection systems are to be counted “since it was a breaker failure.”

While a guidance document can circumvent the plain meaning of “contrary to design” for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4 reliability standard. This results in differing criteria for evaluating which lost/outaged BES Elements/Facilities count towards the three-element threshold.

Includes Minimum Impact Losses

The NERC Glossary definitions of Elements and Facilities specifically list generators as examples. BES Elements and BES Facilities include BES generators. With the revision of the BES definition, Inclusion I4 defines each and all individual dispersed power producing resources as individual BES facilities once they aggregate to greater than 75 MVA and are connected at a voltage of 100 kV or above.

By definition, every outage, contrary to design, of three or more BES wind turbines or solar cells caused by a common disturbance must be reported as a Transmission loss event under EOP-004, even though the loss is labeled as Transmission, contains no transmission elements, and does not meet the threshold for reporting a generation loss.

Blurs Event Types

Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Generation loss has BA reporting loss of MW. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss. This blurs the line between Event Types, obligating the TOP to make determinations to file an Event Report each and every time 3 or more BES wind turbines or solar cells and/or a combination thereof with transmission elements that are lost contrary to design due to a common disturbance. The blurred event types and previously identified conflicting guidance is not conducive to a 24 hour reporting requirement.

TOP’s are unlikely to have this level of visibility into wind/solar farms, necessitating GOP’s to report the loss of these BES Elements to their TOP, so the TOP, as the Responsible Entity, can submit the report. The TOP should not have the responsibility of reporting event types for generator disturbances.

Suggested Remedy

Delete the Transmission loss Event Type from Attachment 1. Events can and should be analyzed under EAP. The EAP is the preferred method as there is collaboration between the reporting entity and the Regional Entity. The data is collected by the RE and NERC and can be analyzed appropriately and lessons learned developed.

Alternatively, clarify the Transmission loss Threshold for Reporting as follows:

“Unexpected loss within its area, contrary to design, of three or more BES Elements (transmission lines or transformers) caused by a common disturbance (excluding successful automatic reclosing, and as-designed protection system operations for the initiating disturbance).

By explicitly stating “BES transmission lines and transformers” we exclude generators as well as the Elements (circuit breakers, busses, and shunt and series devices) that the EAP Addendum says do not need to be included. Adding “as-designed protection system operations” as an exclusion reinforces and reiterates the limitation of losses to those “contrary to design.” The qualifier “for the initiating disturbance” prevents a TOP from claiming that lines tripping on zone 3 relaying for a slow or stuck breaker is operating “as-designed.”

Page 12 of 16 , Row 6

Prior to the implementation of COM-001-2 an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provided for actions to be taken for the loss of Interpersonal Communications. We suggest that the “Complete” loss of voice communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event.

Suggested Change: Complete loss of Interpersonal Communication and Alternate Interpersonal Communication capability at a BES control center.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
On Attachment 1 recommend rewording Event Type "Complete Loss of Interpersonal Communications capability at a BES Control Center" to be "Complete loss of Interpersonal Communication and Alternative Communication capability at a staffed BES Control Center". The COM-001-2 Standard addresses loss of Interpersonal Communication capability.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
With regard to Attachment 1, a change has been made with respect to the Reporting Responsibility for damage or destruction and physical threats to a facility. Accountability has been moved to the Transmission Owner (i.e. Transmission Operator and Balancing Authority have been removed). If this is deemed to be an Owner versus Operator responsibility, why is the same not true for the GO/GOP functions?	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	

Comment	
Hydro One Networks is satisfied with attachment 1. For “Transmission Loss” event type please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as category 1.a. in the EAP).	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Hydro One Networks is satisfied with attachment 1. For “Transmission Loss” event type please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as category 1.a. in the EAP).	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Comemnts as follows:

1. At times there may be a need for a Transmission Operator (“TOp”) to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. Entergy recommends replacing “BA” with initiating Balancing Authority (“BA”) or TOp.

2. The event types with multiple applicable entities such as, “Firm load shedding resulting from a BES Emergency”, “Uncontrolled loss of firm load resulting from a BES Emergency” and “System separation (islanding)” will most likely have the same event reported multiple times if the BA, TOp, or Reliability Coordinator (“RC”) are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type. “Firm load shedding resulting from a BES Emergency” to “Initiating RC, BA, or TOp”. We recommend changing the Entity with Reporting Responsibility for Event Type, “Uncontrolled loss of firm load resulting from a BES Emergency” to just BA. We recommend changing the Entity with Reporting Responsibility for the Even Type, “System separation (islanding)” to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.

3. Under Event Type “Uncontrolled loss of firm load resulting from a BES Emergency” the MW lost amount may be better representative of an

impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.

4. For Event Type Complete Loss of Interpersonal Communications capability at a BES control center, consider also adding Alternative Communication Capability. This will differentiate the event form a COM standard requirement. On event type include the word “staffed” to match working in the Threshold section. Entergy does not agree that the loss of primary/use of backup control center should be a reportable event. Please provide clarification of this point.

Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	

Hydro One Networks Inc. is satisfied with Attachment 1. However, for “Transmission Loss” event type, please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as per Category 1.a. in the EAP).

Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

*Regarding Attachment 1: Reportable Events, BPA recommends clarifying the public appeal for load reduction applicable to the BA by specifying "load reduction" with "**BA** load reduction".*

Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes

Document Name	
Comment	

a. At times there may be a need for a Transmission Operator ("TOp") to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. Entergy recommends replacing "BA" with initiating Balancing Authority ("BA") or TOp.

b. The event types with multiple applicable entities such as, "Firm load shedding resulting from a BES Emergency", "Uncontrolled loss of firm load resulting from a BES Emergency" and "System separation (islanding)" will most likely have the same event reported multiple times if the BA, TOp, or Reliability Coordinator ("RC") are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type. "Firm load shedding resulting from a BES Emergency" to "Initiating RC, BA, or TOp". We recommend changing the Entity with Reporting Responsibility for Event Type, "Uncontrolled loss of firm load resulting from a BES Emergency" to just BA. We recommend changing the Entity with Reporting Responsibility for the Even Type, "System separation (islanding)" to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.

c. Under Event Type "Uncontrolled loss of firm load resulting from a BES Emergency" the MW lost amount may be better representative of an impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.

d. For Event Type Complete Loss of Interpersonal Communications capability at a BES control center, consider also adding Alternative Communication Capability. This will differentiate the event form a COM standard requirement. On event type include the word "staffed" to match working in the Threshold section. Entergy does not agree that the loss of primary/use of backup control center should be a reportable event. Please provide clarification of this point.

Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Thomas - Peak Reliability - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Reclamation agrees with the drafting team's proposal to eliminate duplicative reporting requirements. However, Reclamation suggests that reporting should only be required for "complete loss of ***all*** interpersonal communication capabilities" at staffed control centers. Reclamation requests that the drafting team update this line item because as written, the update could require reporting of the loss of any communication system even when a fully functioning backup system is utilized.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AECI requests the SDT to revise the term BES control center. Control Center is already defined in the NERC Glossary of Terms and should be used in lieu of BES control center throughout the attachment.	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation suggests that reporting should only be required for "complete loss of ***all*** interpersonal communication capabilities" at staffed control centers. Reclamation requests that the drafting team update this line item because as written, the update could require reporting of the loss of any communication system even when a fully functioning backup system is utilized.	
Likes 0	
Dislikes 0	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	No
Document Name	
Comment	
For consistency with our comment on Attachment 1, "Public Appeal" and "System-wide voltage reduction" should remain under the "BES Emergency" heading.	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	No
Document Name	
Comment	
In the header of the Attachment 2, add “select Option 1” after the voice number provided for the submittal of the form. Similar as in the Attachment 1. Under section 4, there are two instances of “Unplanned BES control center evacuation.” Remove the first instance so that the order of the list in Attachment 2 matches the Attachment 1. Attachment 2 is not required for use and it should be stated in Attachment 2 that it is a guidance document, not tied to compliance. The change to attachment 2 implies that it is a compliance obligation to supply a completed Attachment 2 to all entities listed in the Event Reporting Operating Plan. This is not the case as written in R2 and a correction to either Attachment 2 or the requirement language should be made.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
“Unplanned BES control center evacuation” is listed twice on Attachment 2; i.e. as part of the original form (p. 16) and as a new addition (p. 15). Recommend the bullet on p. 16 be retained (as it mirrors the order found in Attachment 1) and the duplicative bullet on p. 15 deleted.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No

Document Name	
Comment	
Texas RE recommends aligning the event types in Attachment 1 with the tasks in Attachment 2. For example, Texas RE noticed the event types "System-wide voltage reduction to maintain the continuity of the BES" and "Firm load shedding resulting from a BES Emergency" are included in Attachment 1, but not listed in Attachment 2.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy recommends that the "Tasks" in Attachment 2 Event Reporting Form align with the Event Types in Attachment 1 if revised by the SDT.	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	
No suggested changes to the text that has been modified. In addition, suspious activity must be listed. Currently, suspicious activity would fall under physical threat to a facility. Taking pictures or flying a drone over a facility could fall under suspicious activity but not always under a physical threat. Suggest adding a suspicious activity line with a check box.	
Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Dislikes 0	
Response	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Any changes to Event Type from comments above carry down to attachment 2 as well.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes
Document Name	
Comment	
Capitalization: As previously noted in our comments, the words "control center" are used in multiple places. Since the term "Control Center" is an approved NERC Glossary Term, we suggest it should be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of control center.	
Likes 0	
Dislikes 0	
Response	

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project

Answer	Yes
Document Name	
Comment	

1. We question if there are any compliance impacts if an entity reports within the required timelines, but uses the previous version of the event reporting form. There are several modifications to Attachment 1. We would like the SDT to clarify whether reporting an event on the previous version of the form would be a violation. This seems to be a potential administrative burden, both for the entities submitting the information, and the Regional Entities and NERC that receive the event reports.
2. We recommend implementing a reporting software tool on the NERC website, which has the capabilities to notify applicable Regional Entities and the DOE of an event. This would alleviate the need to include Attachment 2 as part of the standard and would further streamline the process with a centralized portal for all entities to submit event reports. We ask the NERC standards developer assigned to this project to share this comment with NERC IT department to see if this type of solution is viable.

Likes 0	
Dislikes 0	

Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
Hydro One Networks Inc. is satisfied with Attachment 2. Please also note that the check box item, “Unplanned BES control center evacuation”, is duplicated.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Comment: Any changes to Event Type from comments above should carry down to Attachment 2 as well.	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Hydro One Networks is satisfied with attachment 2. The check box item “Unplanned BES control center evacuation” is duplicated	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Hydro One Networks is satisfied with attachment 2. The check box item "Unplanned BES control center evacuation" is duplicated	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Add ", select Option 1" to the voice number as per the note in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
In the introductory section of the form, the SDT could consider adding the qualifier 'applicable' to organizations to clarify that the reporting requirement is not to all the enumerated organizations: "**Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."**	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	

Answer	Yes
Document Name	
Comment	
Under section 4, there are two instances of 'Unplanned BES control center evacuation.' Remove the first instance so that the order of the list in Attachment 2 matches the Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Refer to comments for #3 above. Attachment 2, Page 15, 4th bullet, "Unplanned BES control center evacuation" is duplicated on Page 16, 5th bullet.	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
"PSEG is pleased to have the opportunity to comment and is in general agreement with the revisions to the standard. The EOP-004 form (Attachment 2) states "Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)." We recommend replacing the term "submit" with "report", or determine if reporting via a different form would meet compliance. Law enforcement, in particular the Regional Operations centers (ROIC) in New Jersey and Connecticut, have a different form (Suspicious Activity Reporting or SAR form) that is used to report events. Therefore, replacing the term "submit" with "report" would aid in harmonizing reporting EOP-004 reporting requirements with processes for reporting events to law enforcement."	
Likes 0	
Dislikes 0	

Response	
Dave Thomas - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - NA - Not Applicable - SPP RE	
Answer	
Document Name	
Comment	
OGE is concerned that the SDT has not looked at some of the CIP standards and how it is tied to the requirements in EOP-004. Currently, there appears to be redundant reporting requirements between CIP-008 and EOP-004. For example, CIP-006 Standard, Part 1.5 states that the Physical Security Plan must describe issuance of an alarm or alert in response to the unauthorized access into or through a Physical Security Access Point, and the alarm or alert must be communicated as identified in the Entity's CIP-008 BES Cyber Security Incident Response Plan. The Response Plan includes reporting of the event to the appropriate agencies (including NERC and DOE). This ties in to the Physical Threats event type in Attachment 1 of EOP-004-4. We believe there is some overlap or at least touchpoints between the two standards, although the CIP standards are focused on protection of the cyber assets, it still includes physical access to these cyber assets. We are requesting the SDT to review the latest versions of the CIP standards (specifically CIP-006 and CIP-008) to ensure there is no overlapping or redundant reporting requirements.	
Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
There should be further revisions to Attachment 1. Specifically, "suspicious device or activity" is ambiguous. Further clarification on "suspicious activity" is needed. For example, does this include photography near a Facility? Also, Attachment 1 should specifically cover cyber related suspicious activity – for example, solicitation attempts or phishing calls at Facilities. There should also be instruction on what an Entity should do if they later realize the incident was NOT suspicious – for example, a prior reported incident which, after further investigation, turns out to be innocuous. The effect of using ambiguous terms and no mechanism for correcting incidents post investigation has left the industry with an output that contains more "trash" than value – many incidents that do not truly meet the definition of EOP 004 are sent out via EISAC which leads to the dilution of truly important incidents.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	
Document Name	
Comment	
Change ‘control center’ to ‘Control Center’ throughout the document to be consistent with the NERC Glossary	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

For all questions the California ISO supports the comments of the ISO/RTO Council Standards Review Committee

Likes 0	
Dislikes 0	

Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment
Texas RE requests the SDT provide rationale for each change made to the Standard. Texas RE would like to better understand the SDT's reasoning in the changings and how they affect reliability. Additionally, Texas RE requests rationale for the implementation plan. The Implementation Plan for the proposed EOP-004 provides that "the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority." Given that registered entities presently are required to submit event reports under the current version of EOP-004 and the revised version largely narrows the scope of such reporting activities, it is unclear why a 12-month implementation period is necessary.

Likes 0	
Dislikes 0	

Response
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Answer	
Document Name	

Comment
Please continue the effort to harmonize NERC Event Reporting requirements with DOE reporting requirements as listed on the OE-417. Currently; it is needlessly burdensome to ensure we meet reporting requirements for both NERC and DOE within specified timeframes. This is particularly difficult considering DOE's 1 or 6 hour submittal requirements and the circumstances a System Operator is likely to be faced with while attempting to submit these reports. **Ideally, DOE would defer to NERC for Event Reporting as required by EOP-004; thus alleviating the potential for separate submissions, on separate forms, with different time requirements for submittal.**

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy recommends that the drafting team revisit the language used in the VSL(s) for R2. The revisions posted for R2 include the addition of the phrase *"specified in EOP-004-4 Attachment 1 to the entities specified"*. The use of *"the entities specified",* does not match up with the language used in the VSL(s) for R2 which use the verbiage "to all required recipients" when describing who an event report should be submitted to. We suggest the drafting team consider using identical language in the Requirements and complementing VSL(s).

Likes 0	
Dislikes 0	

Response

Johnny Anderson - IDACORP - Idaho Power Company - 1

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling

Answer	
Document Name	

Comment

none

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	
Document Name	
Comment	
Change “control center” to “Control Center” throughout the document to be consistent with the NERC Glossary.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	
Document Name	
Comment	
Entergy recommends going to a 72 hour reporting deadline to match the final report deadline for the Department of Energy’s form OE-417.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	
Document Name	
Comment	
SRC suggests one additional improvement to the baseline language. The note in Attachment 1 states that "Under certain adverse conditions (e.g. severe weather, multiple events), it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification." However, this exception doesn’t appear in Requirement R2, which is the source of the reporting obligation. SRC recommends modifying Requirement R2 to explicitly recognize this exception. Also, the above-noted language in Attachment 1 lacks clarity as to exactly what sort of reporting is required when the responsible entity experiences an	

adverse condition and also as to when such a report must be provided. SRC suggests that, when a responsible entity experiences adverse conditions that preclude timely notification of a reportable event, the entity should be allowed to provide either verbal or written notification, and should do so as soon as practicable following the expiration of the 24-hour period for reporting the event. SRC further suggests that, if verbal notification of the event is provided, the responsible entity should submit written notification of the event as soon as practicable after providing the verbal notification. To address these concerns, SRC recommends deleting the exception described above from Attachment 1 and adding the following language at the end of R2: "However, if the Responsible Entity experiences an adverse condition (e.g., severe weather, multiple events) that prevents it from submitting an event report before the expiration of the 24-hour reporting period, it shall provide verbal or written notification of the event to the entities specified in its Operating Plan as soon as practicable thereafter. If the Responsible Entity provides verbal notification pursuant to this exception, it shall provide written notification of the event as soon as practicable thereafter."

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Bonneville Power Administration (BPA) recommends any reference to "BES control center" or "control center" be capitalized and replaced with "BES Control Center" or "Control Center" as a NERC defined term.

Likes 0	
Dislikes 0	

Response

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Dave Thomas - Peak Reliability - 1

Answer	
Document Name	
Comment	

PEAK Reliability supports these changes.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	
Document Name	
Comment	

Capitalization: The Standard's Applicability section states, "…the following functional entities..."

Additionally, the Supplemental Materials, Potential Uses of Reportable Information, the words, "Functional entities" are used.

The term "Functional Entity" is a defined term in the NERC Rules of Procedure, App. 2. Since the references are to Functional Entities defined by the intent and authority under the Rules of Procedure, we suggest functional entity or entities should be capitalized.

Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1

Answer	
Document Name	
Comment	

Although the implementation plan is not specifically referenced in the survey, AECI requests the SDT to revise the proposed effective date of EOP-004-4. The revisions to EOP-004-4 require procedural and reporting changes for Responsible Entities. These modifications should not take a full 12 months to implement and the industry would benefit immediately from the enhanced reporting process. AECI requests the SDT to revise the implementation plan and establish an effective date that is the first calendar quarter that is three (3) months after the date of applicable governmental authority's order approving the standard.

Likes 0	

Dislikes 0	
Response	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	
Document Name	
Comment	
Entergy recommends going to a 72 hour reporting deadline to match the final report deadline for the Department of Energy's form OE-417.	
Likes 0	
Dislikes 0	
Response	
Mike Anctil - Los Angeles Department of Water and Power - 3	
Answer	
Document Name	
Comment	
1. Event Type 2 and 3 on page 10 ("Physical threats to its Facility" and "Physical threats to its BES control center") is too broad and will require entities to file a report for any suspicious activity or device within 24 hours. In the Threshold for Reporting column of these Event Types, it would be better to eliminate "OR Suspicious device or activity at a its Facility. Do not report theft unless it degrades normal operation of a Facility." This elimination would give entities some latitude on determining when a suspicious activity was worthy of a report.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2015-08 Emergency Operations | EOP-004-4
Comment Period Start Date:	7/25/2016
Comment Period End Date:	9/8/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-004-4 EOP-004-4 IN 1 ST 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 NBP IN 1 NB

There were 53 sets of responses, including comments from approximately 134 different people from approximately 47 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

2. Do you agree with the recommendation to retire EOP-004,-3 Requirement R3? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

5. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - EOP Project	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Karl Kohlrus	Prairie Power, Inc.	3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	RF
					Chris Bradley	Big Rivers Electric Corporation	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona's G&T Cooperatives	1	WECC
	Ben Li	2	NPCC		Charles Yeung	SPP	2	SPP RE

Independent Electricity System Operator				ISO/RTO Council Standards Review Committee	Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF
					Karla Jara	PSEG - Energy Resources and Trade LLC	6	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC

					Marjorie Parsons	Tennessee Valley Authority	6	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO

					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
PPL - Louisville Gas and Electric Co.	Robert Tallman	3,5,6	RF,SERC	LG&E and KU Energy	Bob Tallman	LG&E and KU Energy	3,5,6	SERC
					Charlie Freibert	LG&E and KU Energy	3	SERC
					Dan Wilson	LG&E and KU Energy	5	SERC
					Linn Oelker	LG&E and KU Energy	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC

					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC

					Kathleen Goodman	ISO-NE	2	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Don Schmit	Nebraska Public Power District	1,3,5	SPP RE
					James Nail	Independence Power & Light	3	SPP RE
					Michelle Corley	Cleco Corporation	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
Santee Cooper	Shawn Abrams	1		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Chris Wagner	Santee Cooper	1	SERC
					Stony Martin	Santee Cooper	1	SERC
					Chris Jimenez	Santee Cooper	1	SERC
					Glenn Stephens	Santee Cooper	1	SERC
					Diana Scott	Santee Cooper	1	SERC

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Don Schmit - Nebraska Public Power District – 5	
Answer	No
Comment	
NPPD recommends that the parenthetical text be updated to read: (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday**, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day**	
Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3
Response	
Thank you for your comment. The addition of "usually" to the wording does not add any additional clarity to the timing definition. The EOP SDT feels that an addition of "usually" would, in fact, actually lead to reducing clarity to the timing definition. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.	
Richard Vine - California ISO – 2	
Answer	No
Comment	
For all questions the California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Response	

Thank you for your comment. Please see responses to ISO/RTO Council Standards Review Committee.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	No

Comment

The NSRF agrees with R1 and recommends a small change to R2. Recommend the follow additions to clarify that all entities experience "holidays" and those holidays should be included in the same manner as weekends.

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday). The NSRF recommend that the parenthetical text be updated to read (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.

Response

Thank you for your comments. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.

Jamison Cawley - Nebraska Public Power District – 1

Answer	No

Comment

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).

R2 Recommendation:

NPPD recommends that the parenthetical text be updated to read: (which is usually recognized to be 4PM local time on Friday to 8AM local time on Monday**, unless the entity is observing a holiday. For any holiday, the event report shall be submitted no later than then the end of the next business day). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.** Rationale: Events occurring on a Friday after 12:00 p.m. local time or within the same timing prior to a holiday would have to be reported that day. This does not allow enough time for evaluation and development of a report. In addition, consideration for reporting should also be given to holidays observed by the reporting entity.		
Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3	
Response		
Thank you for your comment. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.		
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns		
Answer	No	
Comment		
We agree with R1 and recommend a small addition to R2 to clarify that all entities experience “holidays” and those holidays may vary from entity to entity and should be included in the same manner as weekends. Suggested change to R2: Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entities’ next business day if the event occurs on a holiday or weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday local time). Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the Responsible Entities’ next business day.		

Response	
Thank you for your comments. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	No
Comment	
Texas RE noticed Requirement R1 has the term “event reporting Operating Plan”, while Requirement R2 just says “Operating Plan”. Texas RE recommends adding the descriptor “event reporting” to Requirement R2 or removing it from R1 for consistency. The Requirement R1 VSLs do not include the descriptor except part of the Severe VSL. It appears that the event report should be a written report yet the VSLs for R2 consider a written or verbal event report. Texas RE noticed there is no requirement specifically indicating how events should be reported. Additionally, the VSLs indicate that a verbal report is acceptable. Since an event reporting form exists, Texas RE recommends the requirements specify the form in Attachment 2 be used for event reporting. The language in R2 incorporates the various changes within Attachment 1 by reference. As such, Texas RE’s concerns regarding changes to Attachment 1 should be incorporated herein by reference.	
Response	
Thank you for your comments. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays. **“Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2”** has been added back into Attachment 1 of the standard. Measure M2 also indicates Attachment 2 can be used as evidence for event reporting.	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project	
Answer	No
Comment	

The proposed changes to R2 are not substantive, which raises the question for the need to revise R2 at all. R2 states, "Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type…" This change does not propose any new action, as this is already listed in the Operating Plan. The revision to R2 is not needed.
Response
Thank you for your comment. The EOP SDT drafted revisions to the language in Requirement R2 to tie the types of reporting events as indicated for Attachment 1. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	
We request that the SDT confirm that the time clock starts in R2 upon 'recognition' of the event threshold rather than when the event occurred. There may be analysis of the event that later reveals that the threshold was crossed. We suggest the following clarification to M2 in order to provide additional clarity that this requirement does not supersede any OE-417 reporting timelines. This requirement may allow additional time to report to NERC, but OE-417 requirements may still require reporting within a shorter timeframe. Perhaps all that is needed is the following addition to the proposed M2: M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted **to NERC** within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).	
Response	

Thank you for your comments. Requirement R2 and Measure M2 confirms entities shall report events within 24 hours of recognition of meeting the event type threshold. NERC EOP-004 and DOE OE-417 have separate reporting timeline requirements. In lieu of the EOP-004, Attachment 2, NERC will accept the DOE-OE-417 form as type of evidence for Measure M2.	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	No
Comment	
Kansas City Power and Light Company endorses and incorporates by reference Nebraska Public Power District's response in opposition to Question 1. In addition, we offer the following: **Capitalization**: The words "control center" are used in the Rationale. Since the term is an approved NERC Glossary Term, we suggest it be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of "control center."	
Response	
Thank you for your comment. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Diana McMahon - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Comment	

SRP recommends adjusting the language in R2 to clarify the requirement is referring to events "recognized" during a weekend as opposed to events "occurring" on a weekend. As the current language stands, an event occurring at 7:00 AM on a Monday would have to be reported by the end of the same business day.	
Response	
Thank you for your comments. Requirement R2 and Measure M2 confirms entities shall report events within 24 hours of recognition of meeting the event type threshold. NERC EOP-004 and DOE OE-417 have separate reporting timeline requirements. In lieu of the EOP-004, Attachment 2, NERC will accept the DOE-OE-417 form as type of evidence for Measure M2. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 – WECC	
Answer	Yes
Comment	
SMUD/BANC agrees with the intention that the drafting team is heading with the EOP-004 Draft 4 posting. However, we suggest the Standard Drafting Team consider a minor change to the language in Requirement R2 to address reportable events that occur during holiday periods. We suggest reportable events occurring during holiday be handled in a similar manner that the 'weekend' reportable event schedule that is reported events over the holiday would be reported on next business day.	
Response	
Thank you for your comment. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Comment	
Hydro One Networks is satisfied with the clarification in language in R1 and R2.	

Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	Yes
Comment	

We recommend removing the words “but is not limited to” in M1. This language is no used in R1 and adds no value. It could be interpreted that the Operating Plan must not be limited to the protocols and therefore create an obligation that is not intended to include other elements which are no defined in R1.

M1 should read:

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.

Drafting team should consider adding more specificity to the “other organizations” from Requirement 1. As written this is a potential compliance issue if the Registered Entity elects not to include any “other organizations” such as the Regional Entity or the RC. It is unclear if adding other organizations is voluntary or specifically required by the Requirement.

The examples should be removed unless they are required. These would be more appropriate in the measure, not the language of the requirement. If it is not removed, then the Drafting team should consider removing any entities from the example section not specifically related to the ERO Enterprise. For example, the inclusion of law enforcement is unclear. There are many events listed in Attachment 1 in which law enforcement would not need to be notified. Conversely, there are many types of situations that should be reported to law enforcement that are not considered in Attachment 1. Further, all entities that need to be notified of conditions in real-time should be removed from consideration, such as the RC. Notifications to these types of entities is already required within other standards (changes in operating conditions or capabilities in IRO and TOP standards). As this is in the “Operation Planning” time horizon and will be used to inform the industry as needed and support events analysis the only entities that should be listed in this standard is NERC and the Applicable Regional Entity.

In R1 and R2 all provisions related to weekends should be removed. The standard requires notification within 24 hours of recognition. If an event occurs on the weekend at an unstaffed location and is not recognized until Monday morning, the entity should still have the 24-hour

time frame to complete the notification. As the reporting obligation time frame begins upon "…recognition of meeting an event type threshold for reporting…" there is no need to have a weekend provision. This also removes an ambiguity in R2 which does not have the provision for "recognition of meeting an event type…" for events on the weekend. As written, weekend occurring events must be reported by the end of business Monday regardless of recognizing it as an event identified in Attachment 1. M2 should be revised to remove the implication that EOP-004-4 Attachment 2 or the DOE-OE-417 forms are the only acceptable forms of evidence. As these forms are not specifically listed in the requirement language there should be flexibility written into the measure allowing for other evidence of event reporting. Conversely, the Attachment 2 and OE-417 forms should be listed in the R2 if they are required to demonstrate compliance.	
Response	
Thank you for your comments. The EOP SDT agrees with your comment to strike "but is not limited to." It is up to the RE in their event reporting Operating Plan to identify all organizations that should be notified, as stated in Measure M1. The EOP SDT finds the language in Requirement R1 is clear as written. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays. **"Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2"** has been added back into Attachment 1 of the standard. Measure M2 also indicates Attachment 2 can be used as evidence for event reporting. Measure M2 lists the following examples of evidence to demonstrate compliance: "(e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile)."	
Oliver Burke - Entergy - Entergy Services, Inc. – 1	
Answer	Yes
Comment	
No comments.	

Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
Hydro One Networks Inc. is satisfied with the clarification provided and language in R1 and R2.	
Response	
Thank you for your support.	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Comment	
NV Energy agrees with R1 and recommends a minor change to R2 to consider holidays and recommends that for any holiday, the event report shall be submitted no later than then the end of the next business day. Also, for events occurring after noon (12:00 p.m. local time) on a day prior to a weekend or holiday, the event report shall be submitted no later than the end of the next business day.	
Response	
Thank you for your comment. The EOP SDT drafted revisions to the language in Requirement R2 for clarity; to remove the ambiguity for weekends and to add clarity for holidays.	
Jaclyn Massey - Entergy - Entergy Services, Inc. – 5	
Answer	Yes
Comment	
None	

Response	
Mary Cooper - Alameda Municipal Power - 3,4 – WECC	
Answer	Yes
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 – SERC	
Answer	Yes
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Jeffrey DePriest - DTE Energy - Detroit Edison Company – 5	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 – SERC	
Answer	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	Yes

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes

Quintin Lee - Eversource Energy – 1	
Answer	Yes
Sean Bodkin - Dominion - Dominion Resources, Inc. – 6	
Answer	Yes
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Thomas Foltz - AEP – 5	
Answer	Yes
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Michelle Amarantos - APS - Arizona Public Service Co. – 1	
Answer	Yes
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) – 3	
Answer	Yes
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	Yes
Johnny Anderson - IDACORP - Idaho Power Company – 1	
Answer	Yes
Jennifer Wright - Sempra - San Diego Gas and Electric – 1	
Answer	Yes
Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	Yes
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Erika Doot - U.S. Bureau of Reclamation – 5	
Answer	Yes
Dave Thomas - Peak Reliability – 1	
Answer	Yes

Mark Riley - Associated Electric Cooperative, Inc. – 1	
Answer	Yes

2. Do you agree with the recommendation to retire EOP-004,-3 Requirement R3? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	No
Comment	
Texas RE is concerned that contact list will not be updated if there is no requirement to do so. By removing the obligation, entities may learn of an outdated contact when the contact is needed.	
Response	
Thank you for your comment. Requirement R3 was removed because it is administrative in nature. While it is a good practice to keep the contact list updated, the EOP SDT did not feel that it should be a requirement in a NERC Reliability Standard.	
Jaclyn Massey - Entergy - Entergy Services, Inc. – 5	
Answer	Yes
Comment	
None	
Response	
Erika Doot - U.S. Bureau of Reclamation – 5	
Answer	Yes
Comment	

The Bureau of Reclamation agrees with the drafting team’s proposal to retire EOP-004 Requirement R3 because it is administrative in nature.

Response	
Thank you for your support.	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project	
Answer	Yes
Comment	
We agree with the retirement of Requirement R3, because there are administrative aspects to this requirement.	
Response	
Thank you for your support.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
Hydro One Networks Inc. is satisfied with the removal of R3.	
Response	
Thank you for your support.	
Oliver Burke - Entergy - Entergy Services, Inc. – 1	
Answer	Yes
Comment	

No comments.
Response
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling

Answer	Yes

Comment
Hydro One Networks is satisfied with the removal of R3.
Response
Thank you for your support.
Thomas Foltz - AEP – 5

Answer	Yes

Comment
While we agree with the proposed retirement of R3, we believe the RC should gather and provide (perhaps on their website) contact information for applicable RCs, REs, and TOs within their footprint to ensure that reports are provided to appropriate entities.
Response
Thank you for your comment. While it is a good practice to keep the contact list updated, the EOP SDT did not feel that it should be a requirement in a NERC Reliability Standard.
Mark Riley - Associated Electric Cooperative, Inc. – 1

Answer	Yes

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Dave Thomas - Peak Reliability – 1	
Answer	Yes
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	Yes
Jennifer Wright - Sempra - San Diego Gas and Electric – 1	

Answer	Yes
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	Yes
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 – WECC	
Answer	Yes
Johnny Anderson - IDACORP - Idaho Power Company – 1	
Answer	Yes
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) – 3	
Answer	Yes
Michelle Amarantos - APS - Arizona Public Service Co. – 1	
Answer	Yes
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Jamison Cawley - Nebraska Public Power District – 1	
Answer	Yes
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Don Schmit - Nebraska Public Power District – 5	
Answer	Yes
Diana McMahon - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes
Sean Bodkin - Dominion - Dominion Resources, Inc. – 6	
Answer	Yes
Quintin Lee - Eversource Energy – 1	
Answer	Yes

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	Yes
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	

Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 – SERC	
Answer	Yes
Jeffrey DePriest - DTE Energy - Detroit Edison Company – 5	
Answer	Yes
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 – SERC	
Answer	Yes
Mary Cooper - Alameda Municipal Power - 3,4 – WECC	
Answer	Yes

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Jeffrey DePriest - DTE Energy - Detroit Edison Company – 5

Answer	No

Comment

No suggested changes to the text that has been modified. In addition, suspicious activity must be defined.

Response

Thank you for your comment. Suspicious Activity should be defined by each entity. Suspicious Activity is company-specific in its event reporting Operating Plan.

Leonard Kula - Independent Electricity System Operator – 2

Answer	No

Comment

We do not agree with the following changes:

1. For the Event Type "Public appeal for load reduction": It is unclear what "maintain the continuity of the BES" really means. By "continuity", does it mean "integrity of the BES" or "continuity of supply"? This needs to be revised to be more specific and to improve clarity.
2. Assigning the TOP to be the responsible entity for reporting system wide voltage reduction

Voltage reduction is intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend changing it to the BA. Also, similar to the comment above, it is unclear what "maintain the continuity of the BES" really means. By "continuity", does it mean "integrity" or "continuity of supply"? Either way, we do not see the value added or the necessity of the having this qualifier. We

suggest to revise the Event Type to "System wide voltage reduction" or where a qualifier is deemed to add value, change it to "System wide voltage reduction to maintain load supply" or "to meet system demand". 3. The Event Type "Firm load shedding resulting from a BES Emergency": the basis for the reporting threshold, i.e., 100 MW, etc. has not been provided. We would appreciate the SDT providing the technical basis/justification other than just because it existed before.	
Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Response	
Thank you for your response regarding Public Appeal for load reduction to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The OE-417 says, "Maintain the continuity of the electric power system." And continuity of the BES is intended as to remain interconnected. EOP-011-1 and the VAR standards puts the requirements of the voltage reduction (transmission system reconfiguration) on the TOP; therefore, the BA should not be added to the reporting category. Thank you for your response regarding Firm load shedding resulting from a BES Emergency to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. NERC and the U.S. Department of Energy request this information in order maintain better situational awareness.	
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	No
Comment	
LG&E and KU Energy ("LG&E/KU") appreciates the opportunity to submit this comment for the Standard Drafting Team's consideration. The reportable event type "Complete loss of Interpersonal Communication capability at a BES control center" has a threshold for reporting of "Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more." LG&E/KU proposes the event type be rewritten as "Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability at a BES control center". Furthermore, LG&E/KU proposes changing the threshold for reporting to read "Complete	

loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability affecting a staffed BES control center for 30 continuous minutes or more.”	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., NA - Not Applicable, Tay Sing
Response	
Thank you for your comment. The EOP SDT agrees with your comment and has added “Alternative Interpersonal Communications.” The EOP SDT discussed your comment on the 30-minute requirement and it is appropriately covered in the threshold.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Comment	

CenterPoint Energy appreciates the SDT’s time and effort towards the improvement of the Event Reporting Standard and is agreeable to the proposed revisions to R1 and R2, and the retirement of R3. However, CenterPoint Energy believes that proposed revisions to Attachment 1 may not be completely clear to the industry and would like the SDT to consider the following:

The proposed revisions regarding the “public appeal for load reduction” Event Type appears to expand the threshold to include events beyond the NERC defined “BES Emergency” which is defined as: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System”. CenterPoint Energy believes removing BES Emergency as a threshold and adding the phrase “continuity of the BES” is ambiguous. The Company appreciates the SDT aligning the language with DOE OE-417; however, DOE OE-417 instructions state that the report should be made only if an appeal is made during emergency conditions. Therefore CenterPoint Energy recommends the reporting threshold read, “BES Emergency requiring public appeal for load reduction to maintain continuity of the BES.

CenterPoint Energy also has a similar concern regarding the use of “continuity of the BES” for the proposed changes to the “System-wide voltage reduction…” event type. CenterPoint Energy believes that for consistency the Event type should read, “System-wide voltage reduction” and the threshold for reporting should read, “BES Emergency requiring system wide voltage reduction of 3% or more to maintain continuity of the BES.”

In the “BES Emergency requiring manual Firm load shedding” event type, removing the word “manual” potentially broadens the scope and may also include automatic firm load shed, which would incorporate UFLS and UVLS. With these revisions and with the deletion of the Event

Type, “BES Emergency resulting in automatic firm load shedding”; is it the SDT’s intent to consolidate all firm load shedding into one event type regardless of whether it is performed automatically or manually? If this is so, are UVLS, UFLS , and RASs still considered as automatic firm load shedding as it would be considered in the revised “Firm load shedding resulting from a BES Emergency” Event Type?

CenterPoint Energy considers manual and automatic Firm load shedding to be “controlled” actions that are deliberate and by design, regardless of whether initiated by a System Operator or relay scheme that is triggered by a threshold being met. CenterPoint Energy recommends the “Threshold for Reporting” to read, “Controlled Firm load shedding, manual or automatic via an Undervoltage Load Shedding Program, under-frequency load shedding scheme, or by Remedial Action Scheme ≥ 100 MW.

Response

Thank you for your comment. The EOP SDT agrees with your comments for public appeal for load reduction, as well as your comment for system-wide voltage reduction and have made the conforming changes. The EOP SDT added “(manual and automatic)” to the reporting threshold for Firm load shedding.

Don Schmit - Nebraska Public Power District – 5

Answer	No

Comment

First Recommendation: Delete the Transmission loss Event Type in Attachment 1.

Rationale:

1. The EOP-004 reporting should stay focused on larger events, such as the criteria under Generation loss (Total generation loss, within one minute, of greater than or equal to 2,000 MW for entities in the Eastern or Western interconnection). Three transmission elements provide a very low threshold identified in the Transmission loss section. These low impact events can be better handled through the NERC Event Analysis Program (EAP). The EAP has matured over time and now provides an excellent means to identify and document lessons learned from events.

2. The Event Analysis Program (EAP) is providing a back door for changes to the EOP-004 reporting process without changes to the EOP-004 reporting process being vetted through the Standards Development Process. Case in point, an entity recently filed an EAP notification for a slow breaker trip impacting three or more elements and in which all related relaying operated by design. The Regional Entity directed that the entity report under the EOP-004 reporting process. The EOP-004 Event Type clearly states three

elements “contrary to design”. With continual changes to the EAP and the dissimilarities in the two processes (EAP/EOP) these changes and differences are clearly leading to confusion for both the reporting entity and the Regional Entities. 3. The EAP is a robust and documented process that provides for interaction between the Regional Entity and the reporting entity in the classification of Event types. All reporting for NERC/FERC classification of Events can be handled under the EAP process for this Event type, along with the current reporting under TADS and GADS. Lessons Learned are developed through this EAP process for the industry to learn from these events. The Transmission loss Event type under the EOP provides no further benefit and, in fact, as noted creates confusion on application for reporting. 4. The definition of BES Element in this EOP-004 Event type (Transmission loss) includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event type and also leads to confusion as to the element count for three elements contrary to design. In addition, the Event Analysis Program (EAP) uses the definition of “BES Facility” in its application and not “BES Element” as used in the EOP Event type which leads to further confusion in evaluating reporting during an Event.	
Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3
Response	
Thank you for your response regarding Generation. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The EOP SDT agrees with your comment and has added “Alternative Interpersonal Communications.” The EOP SDT discussed your comment on the 30-minute requirement, and it is appropriately covered in the threshold. Transmission loss: The SDT appreciates your comment about removing Transmission Loss from Attachment 1; but after many discussions, the SDT felt there was still a need for this reporting requirement. Threshold changes: “Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).”Element: The EOP SDT agrees with your comment and has made the conforming change from “Element” to “Facility.”	
Thomas Foltz - AEP – 5	
Answer	No

Comment	
It may be beneficial to provide general guidance (perhaps at the very top of the table), exactly which entity has the reporting responsibility. If an entity directs another entity to perform an action, the entity issuing the directive would have the reporting responsibility. In all other instances, the responsible party would be the entity who actually experienced the event. For example, such clarity might be beneficial in cases where the RC is the TOP.	
Response	
If an event applies to any of the entities listed as the "entities with reporting responsibilities," then it is up to those entities to ensure reporting is done. Whether it be reporting the event themselves or delegating reporting responsibilities, this should all be covered in the entity's event reporting Operating Plan.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Comment	

First Recommendation: Delete the Transmission loss Event Type in Attachment 1.

Rationale:

1. The EOP-004 reporting should stay focused on larger events, such as the criteria under Generation loss (Total generation loss, within one minute, of greater than or equal to 2,000 MW for entities in the Eastern or Western interconnection). Three transmission elements provide a very low threshold identified in the Transmission loss section. These low impact events can be better handled through the NERC Event Analysis Program (EAP). The EAP has matured over time and now provides an excellent means to identify and document lessons learned from events.

2. The Event Analysis Program (EAP) is providing a back door for changes to the EOP-004 reporting process without changes to the EOP-004 reporting process being vetted through the Standards Development Process. Case in point, an entity recently filed an EAP notification for a slow breaker trip impacting three or more elements and in which all related relaying operated by design. The Regional Entity directed that the entity report under the EOP-004 reporting process. The EOP-004 Event Type clearly states three

elements "contrary to design". With continual changes to the EAP and the dissimilarities in the two processes (EAP/EOP) these changes and differences are clearly leading to confusion for both the reporting entity and the Regional Entities.

3. The EAP is a robust and documented process that provides for interaction between the Regional Entity and the reporting entity in the classification of Event types. All reporting for NERC/FERC classification of Events can be handled under the EAP process for this Event type, along with the current reporting under TADS and GADS. Lessons Learned are developed through this EAP process for the industry to learn from these events. The Transmission loss Event type under the EOP provides no further benefit and, in fact, as noted creates confusion on application for reporting.

4. The definition of BES Element in this EOP-004 Event type (Transmission loss) includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event type and also leads to confusion as to the element count for three elements contrary to design. In addition, the Event Analysis Program (EAP) uses the definition of "BES Facility" in its application and not "BES Element" as used in the EOP Event type which leads to further confusion in evaluating reporting during an Event.

Likes 1	Webb Douglas On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3

Response

Thank you for your response regarding Generation. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications."
The EOP SDT discussed your comment on the 30-minute requirement and it is appropriately covered in the threshold.
Transmission loss: The SDT appreciates your comment about removing Transmission Loss from Attachment 1 but after many discussions the SDT felt there was still a need for this reporting requirement. Threshold changes: "Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing)." The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility."

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No

Comment
We request that the proposed revision to the category for 'Complete Loss of Interpersonal Communication Capability at a BES control center' be clarified to state that the threshold requires loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities. We believe that is the intent of the threshold which is consistent with the EAP. However, since both Interpersonal Communication and Alternative Interpersonal Communication are defined terms it is unclear from the posted Attachment 1 language whether this is the intention of the SDT. Accordingly, we propose rewording the reporting threshold to: Complete loss of both Interpersonal Communication and Alternative Interpersonal Communication capabilities at a BES control center. In addition, the category for a 'Complete loss of off-site power to a nuclear generating plant (grid supply)' could be better aligned with the EAP. The EAP refers to a 'LOOP event' which could be referenced here to provide consistency. Alternatively, the EAP could be updated to better align with the proposed revision. In addition, the current use of the phrase "complete loss of off-site power" in the Event Type as well as the Threshold for Reporting is problematic for the TO, TOP to be the Entity Responsible for Reporting. Loss of off-site power (LOOP) is a well-defined term in the nuclear industry and is heavily dependent on in-plant alignments and operating conditions as well as transmission configuration which the TO/TOP has only has a partial awareness of. Nuclear Plant Interface Requirements are intended to ensure that the NPGO has all of the information necessary to determine the operability of off-site power per the plant license agreement. Should the existing wording of the Event Type and Threshold for Reporting be kept the Entity with Reporting Responsibility should be changed to the Nuclear Plant Generator Operator rather than the TO/TOP since the TO/TOP does not have the knowledge nor expertise to determine when a loss of off-site power condition exists. Similar to NERC accepting the DOE OE-417 report there is a higher degree of efficiencies and effectiveness of reporting for the NPGO since loss of offsite power events are reportable to other regulators under plant licensing requirements. Different Functional Entities independently reporting of the same event to different regulators creates a significant opportunity for confusing or even possibly conflicting information.
Response
Thank you for your comment. The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications." The EOP SDT discussed your comment on the 30-minute requirement and it is appropriately covered in the threshold. The EOP SDT has added loss of off-site power"(LOOP)." The EOP SDT discussed your comment but will leave the TO/TOP for reporting responsibility.
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Comment	

Texas RE is concerned that the following proposed changes to EOP-004 Reportable Events could lead to gaps in reliability and confusion among registered entities.

- Texas RE is concerned that the proposed revisions eliminate the requirement that Reliability Coordinators (RC) submit event reports in connection with situations in which there are operations outside the IROL for a time greater than the IROL's Tv (typically 30-minutes). The management of IROLs is a key aspect of a RC's constraint management activities. In particular, situations in which an IROL is exceeded for a period sufficient to trigger an unacceptable risk to the interconnection or other Reliability Coordinator Areas represents a significant systemic event. While such an exceedance may be investigated in the compliance or enforcement process, there is necessarily a delay in these activities. The contemporaneous reporting obligations serve to ensure that the NERC regions have immediate knowledge that a significant risk of a cascading outage has occurred, permitting the region or regions to begin steps to identify the root cause and develop appropriate mitigation. Because such awareness appears critical to the core reliability functions performed within the NERC regions, Texas RE cautions against eliminating this requirement. At a minimum, Texas RE requests that the SDT provide a rationale for why the IROL Tv event reporting requirement should be removed, including whether the SDT believes that the event reporting aspects of EOP-004 are adequately addressed in other standards.

- Texas RE has noted that the SDT proposes to eliminate the event reporting obligations of certain NERC functions. For example, the proposed revisions would no longer require DPs to report automatic firm load shedding resulting from a BES Emergency. Similarly, the proposed revisions no longer require GOPs to report generation loss in excess of 1000 MW in the ERCOT region. Texas RE requests that the SDT provide the rationale for narrowing these event reporting obligations. If the SDT believes that such reporting obligations are duplicative, Texas RE would also request evidence supporting that assertion.

- Based on its own engagement with registered entities in the ERCOT region, Texas RE also believes there is some confusion regarding event reporting terms. In particular, the distinction between "Firm load shedding resulting from a BES Emergency" and "Uncontrolled loss of firm load resulting from a BES Emergency" appears unclear. "Firm load shedding" could be read to refer solely to intended load shedding events (either manual or automatic). If so, the SDT may wish to consider replacing the term "uncontrolled" with "unintended" to better capture the distinction between intentional and unintentional firm load shedding.

- It appears the "Public appeal" for load reduction ignores localized situations that may still require a localized public appeal that may be better facilitated by a TOP or DP (and actually recognized later in the loss of load issues). Texas RE requests rationale for the change.
- Texas RE noticed the event type "Voltage deviation on a Facility" did not include the GOP. "Voltage deviation on a Facility" could occur at a GOP site as well and should be recognized since the GOP is to maintain that voltage. Texas RE inquires as to why was the GOP is not included.
- It appears the eliminated event type "BES Emergency resulting in automatic firm load shedding" is intended to be captured in the event type "Firm load shedding resulting from a BES Emergency", however the same functions are not captured. Texas RE requests clarification and rationale from the SDT regarding this change. Texas RE is concerned the removal of reporting UVLS/UFLS/RAS load shedding reduces situational awareness for the RC and other functional entities.
- Texas RE requests rationale for the event type "Complete loss of Interpersonal Communication capability at a BES control center". Texas RE is concerned the term "BES control center" is undefined and might cause confusion. Additionally, it ignores the DP and GOP responsibilities for having Interpersonal Communication.
- Texas RE inquires as to why a GOP Control Center is not considered in any of the event thresholds (and why is the undefined term "BES control center" limited to BA, RC, and TOP functions?)
- For the event type "Firm load shedding resulting from a BES Emergency", Texas RE inquires if the SDT intends for an event to be reported in a case where a RAS intentionally sheds load in response to a contingency for which the RAS was designed?
- For the event type "Transmission loss", Texas RE suggests adding the RC to the reporting responsibility. This event type implies that the three or more elements that are lost are within a single TOP boundary. We have numerous examples of events affecting multiple entities and elements outside of a single TOP boundary.
- To maintain alignment between EOP-004 and the NERC Events Analysis Process, we suggest adding an event type for reporting the failure or misoperation of a RAS.

Response

The EOP SDT appreciates your comments.

IROL proposed retirement: TOP-001-3, Requirement R12 becomes effective 4/1/17, requiring a self-report if Tv is exceeded; TOP-007-WECC-1 is pending retirement. Even though the EOP SDT removed the reporting requirement from the GOPs that this should be the requirement of the BA. The EOP SDT added "(manual and automatic)" to the reporting threshold for Firm load shedding. Thank you for your response regarding Public Appeal. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. Voltage deviation: The TOP is the correct entity for reporting. The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications." The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers. Transmission loss: The intention is that the TOP, where the disturbance originated, will have the reporting responsibility. The EOP SDT discussed your RAS comment but do not agree with your comment to add an event type for reporting.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Comment	
Duke Energy provides comment on the following Event Types: Public Appeal for load reduction: The proposed language for this event includes the phrase *"to maintain continuity of the BES"*. While we agree with the intent of the revisions, we disagree with the verbiage used. We do not believe that maintaining continuity of the BES is a concept that is widely understood by the industry, and suggest that using "to maintain reliability of the BES" would be more widely understood and accepted by the industry. System-wide voltage reduction to maintain the continuity of the BES: Please see our comment above regarding the use of the phrase "*to maintain continuity of the BES*". Also, we request further explanation from the drafting team on singling out the TOP as the entity with reporting responsibility. This concept may be particularly troublesome for vertically integrated entities. Entities that are integrated BA/TOP, either the BA or TOP can initiate voltage reduction. Lastly, the voltage reduction actually takes place on the distribution system, so we	

request further clarification of the singling out of the TOP only for this event, and request the drafting team consider adding the BA as an entity responsible for reporting for this event type. Firm load shedding resulting from a BES Emergency: Some ambiguity may exist with having the multiple entities listed as being responsible for reporting per event. For example, a BES Emergency arises wherein an RC directs a BA/TOP to shed firm load. Following the language found in Attachment 1 of this standard, it is unclear whether the RC should file the event report, the BA/TOP would file the event report, or both. Is it the drafting team's intent to have all or both functions submit an event report. If the intent is just for one report per event type to be filed, some language needs to be added affording entities the opportunity to discuss and decide which function will submit the event report. In the Guidelines and Technical Basis section of this standard, there is a section for Multiple Reports for a Single Organization. Perhaps a section could be added regarding reports involving multiple functions that stems from one event, and who is the responsible party for the reporting. Uncontrolled loss of Firm load resulting from a BES Emergency: We requests further clarification from the drafting team on the addition of the term "Uncontrolled", and whether or not using the term now negates the use of the DOE form for NERC reporting. This may result in an entity having to fill out two separate reports. Was this the drafting team's intent? Also, is the term "Uncontrolled" referring to Operator controlled? Please clarify. Transmission Loss: There appears to be a disconnect between the definition of BES Element in the NERC standards process, and the NERC Events Analysis process. We feel that a great deal of confusion exists on the reporting for this type of event. We request the drafting team to consider revising the associated language of this event type to help narrow down the intended scope of this event. As of now, the language is so broad that entities spend a considerable amount of time creating reports for this event type, and would greatly benefit by narrowing the scope or revising the language to better demonstrate intended expectations.
Response
Thank you for your response regarding Public Appeal for load reduction to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. And continuity of the BES is intended as to remain interconnected. EOP-011-1 and the VAR standards puts the requirements of the voltage reduction (transmission system reconfiguration) on the TOP; therefore, the BA should not be added to the reporting category.

Given there are regional and registration differences, the intent of the EOP SDT is for one of the entities to have the reporting responsibility. Thank you for your response regarding Uncontrolled loss of firm load, the updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The EOP SDT is working with the DOE to have all EOP-004 event categories listed on the OE-417 reporting form that is available online; therefore, this could be the one place for EOP-004 and DOE reporting to be done. The EOP SDT has added “Alternative Interpersonal Communications.” Staffed: Staffed has been added to the event types and thresholds.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	No
Comment	

There are numerous “its” references in the description of the Event Type, but not clear who this is in reference to? Is it intended to imply that “its” is in referencing the Functional Entity that’s identified in the respective row of the second column – “Entity with Reporting Responsibility”? Will these always match up? Are there instances where the reporting entity and the owning entity are different? For example, in ISO-NE the RC submits all the reports. This may need some clarity.

GOP should be removed from the “Entity with Reporting Responsibility” for the “Physical Threats to its Facility” event type and added to the “Physical threats to its BES control center” event type. Facility is defined as – “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” and thus does not capture a GOP control center. So in order for these critical assets to be captured in the physical threats reporting requirements of the Attachment 1, GOP must be added to the “Physical threats to its BES control center” event type.

Same as comment 2 for “Physical threats to its Facility” event type.

For the “Public appeal for load reduction” event type, TOP should be added to the “Entity with Reporting Responsibility”. EOP-001-2.1b, R4 – “R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.”

Attachment 1-EOP-001, Elements for Consideration in Development of Emergency Plans

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.

"System-wide voltage reduction to maintain the continuity of the BES" event type

a. BAs and RCs can potentially implement a system-wide VR due to capacity and energy emergencies in accordance with their emergency plans, as required under EOP-002-3.1 - Capacity and Energy Emergencies, so we don't see why these functions are being excluded from the reporting requirement.

b. should be better aligned with the EAP event category 1d –

Recommend –

Threshold for reporting – no change

Event Type –System-wide voltage reduction in accordance with the entity's emergency plan resulting from a BES Emergency.

c. Threshold requirement of "system wide" should be clarified to specify whose system it is. This is a similar ambiguity as the one being requested for clarity in item 1 above. Are we implying that it's the TOP's (Entity withy Reporting Responsibility) system? Are there instances when the requesting entity is a BA/RC requesting a voltage reduction for a particular TOP? In such cases, would it be reportable and who would be the Entity with reporting responsibility. Is the intent to require reporting of such events? Should BAs and RCs be added to the Reporting Entities?

EOP-002-3_1 R6 -

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

For “Transmission Loss” event type please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as category 1.a. in the EAP).

For the transmission loss category: The term “contrary to design” should be better defined. In October 2015 an addendum for Category 1a Events was created for the Event Analysis Process. This addendum indicates that breaker failure operations are not as intended. Is the intent to mimic the EA Process? Also, the term “excluding successful automatic reclosing” does not align with the EA Process language for Transmission loss.

NERC Definition of Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Definition of Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.

The intent is to capture the outage of three or more Facilities (each Facility can be comprised of two or more Elements), not the underlying Elements.

Loss of firm load (BA, TOP, DP) - Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year’s demand ≥ 3,000 OR ≥ 200 MW for all other entities.

Recommend adding the following qualifiers:

· This does not include the loss of load when it is caused by “customer actions to protect their systems” and not the utility (e.g. customer’s relays settings to swap over to own generation set higher than the utility’s UFLS/UVLS settings).

· This excludes radially connected industrial load loss. Design and level of reliability was approved and accepted.

Suggest replacing the “uncontrolled” in the Event Type with the “unintended” language (similar to the EAP category). “Uncontrolled” implies or may get interpreted as a cascading type of an event, limiting the reporting requirement to only those types of events.

Add GOP to the Entity with Reporting Responsibility. Similar reasons specified in the Attachment 1, Item 2 above. Additionally, if the GOP BES control centers are subject to consideration and classification as High, Medium and Low impact facilities in accordance with the CIP-002 evaluation, they should be considered in this reporting criteria, at least for the GOP's Control Centers that meet the reporting threshold for "Generation Loss" event type (≥ 2,000 MW for entities in the Eastern, or Western, or Quebec Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection); or, as an alternative, High Impact (as classified under the CIP-002) control centers – CIP-002-5.1 - Attachment 1 Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H) Each BES Cyber System used by and located at any of the following: 1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

Complete loss of monitoring capability (RC, BA, TOP)- Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or {more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.}

Add the word "staffed" to the threshold column for "Complete loss of monitoring or control at a BES control center" so that it is consistent with the event Type above it which states: Complete loss of Interpersonal Communication capability affecting a "staffed" BES control center for 30 continuous minutes or more.

The BA should also be identified as an "Entity with Reporting Responsibility" for System-wide voltage reduction since according to the functional model the BA may request the TOP or directly address a DP to reduce voltage to ensure balance within its BA area.

Agree with the changes eliminating the bracketed statement as it is not indicative of a complete loss of monitoring capability and has caused confusion throughout the industry.

Response

Thank you for your comments. The three event types that include 'its' are; Damage or destruction of its Facility (TO, TOP, GO, GOP, DP), Physical threats to its Facility (TO, TOP, GO, GOP, DP) and Physical Threats to its BES control center (RC, BA, TOP) and with the specific entities listed for reporting, the event type and reporting entity will match up.

There could be instances where the reporting entity and owner are different, but that is up to the entity to ensure reporting is done based on their registration type. The SDT tried to streamline this as much as we could; to try to reduce multiple reports and focus on the 'owner' or best qualified entity, to do the necessary reporting. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers. EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. EOP-011-1 and the VAR standards puts the requirements of the voltage reduction (transmission system reconfiguration) on the TOP; therefore, the BA should not be added to the reporting category. Thank you for your response regarding System-wide voltage reduction, the updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The EOP SDT is working with the DOE to have all EOP-004 event categories listed on the OE-417 reporting form that is available online; therefore, this could be the one place for EOP-004 and DOE reporting to be done. EOP-004 Attachment 2 and OE-417 are mandatory reporting forms; whereas, EAP reporting is not mandatory. The current EOP-001, EOP-002 and EOP-003 standards will be retired 4/1/17 and EOP-011-1 will replace these standards and become effective on 4/1/17. EOP-011 will incorporate requirements from EOP-001, EOP-002 and EOP-003. The SDT used EOP-011 as a guide, which separated the BA and TOP responsibilities that need to be included in their Operating Plan to mitigate operating Emergencies. Your Question C above related to system-wide and TOP as reporting entity: It is the intent of the EOP SDT that the TOP only reports System-wide voltage reduction events. The intent is for TOP to report and initiate System-wide voltage reductions. The SDT developed this Rationale for the above;"System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction." The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility." In response to your comment on firm load reporting, the EOP SDT updated the event type to read: "Uncontrolled loss of firm load resulting from a BES Emergency;" and therefore closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. So if the qualifiers you mentioned above are not from a BES Emergency, then the loss would not need to be reported. Staffed: Staffed has been added to the event types and thresholds.
Jennifer Wright - Sempra - San Diego Gas and Electric - 1

Answer	No
Comment	

We do not agree with the elimination of "BES Emergency requiring" for a public appeal for load reduction. During periods of very hot weather or other high load situations, even though there is not a BES emergency there are public appeals to exercise conservation to ensure sufficient resources on a regional or statewide basis. Reporting to NERC of public appeals for load reduction or conservation should only be required for BES emergency conditions as written in the current version.

Response

Thank you for your response regarding Public Appeal for load reduction to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. The EOP SDT has updated the reporting category to: Public appeal for load reduction resulting from a BES Emergency. The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility."

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Comment	

ERCOT joins the comments of the ISO RTO Council (IRC) Standards Review Committee (SRC). In addition, ERCOT provides the additional comment below.

a. We ask the SDT to consider setting the reporting criteria for the "Generation loss" event type in ERCOT at 1,400 MW rather than 1,000 MW. This would align the current reportable MW threshold for ERCOT with the NERC Event Analysis process threshold for a Category 3 event.[1] As currently written, entities in the Eastern Interconnection are required to report in the event of a Category 3 event with a loss of generation of 2,000 MW or more, while ERCOT would be required to report in the event of a Category 1 event with a loss of generation of 1,000 MW. Setting the reporting threshold at 1,400 MW for generation loss in ERCOT would establish equitable criteria for reporting in the ERCOT interconnection.

[1] http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_EAP_V3_final.pdf

Response

Thank you for your comments. Please see responses to ISO RTO Council (IRC) Standards Review Committee (SRC). To establish the equitable criteria for reporting in the ERCOT interconnection, the EOP SDT has revised the reporting threshold from 1,000 MW to 1,400 MW for generation loss in the ERCOT interconnection. Please refer to the project's mapping document for the technical justification regarding this revision.

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee

Answer	No

Comment

We do not agree with the following changes:

a. For the Event Type "Public appeal for load reduction": It is unclear what "maintain the continuity of the BES" means. Does "continuity" mean "integrity of the BES" or something else? This needs to be revised to be more specific and to improve clarity.

b. The phrase "Public appeal for load reduction to maintain continuity of the BES" could also unreasonably expand the number of required reporting instances. Public appeals are made in many different types of situations. Reliability Coordinators often make appeals when an emergency is only a possibility and not a likelihood. In many of these cases, the risk of an emergency condition is somewhat lower and should not rise to the level of concern to justify official event reporting. SRC therefore recommends that the SDT retain the defined term "BES Emergency" and use the phrase "Public appeal for load reduction in a BES Emergency to maintain integrity of the BES."

c. The SRC also disagrees with assigning the TOP the responsibility for reporting system wide voltage reduction. Voltage reduction is intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend making the BA the responsible entity. Further, we don't agree with making every public appeal for demand reduction a reportable event. The redline removes the words "BES Emergency requiring…" and we believe that the words should remain so that only voltage reduction associated with BES Emergencies are reportable. " Also, similar to the comment above, it is unclear what "maintain the continuity of the BES" means. We suggest to revise the Event Type to "Voltage reduction" or where a qualifier is deemed to add value, change it to "Voltage reduction to meet system demand".

d. For consistency with comment (b) above "Public Appeal" should remain under the "BES Emergency" heading.

e. Having proposed the above, the SRC suggests that Public Appeal be removed from the list of Events to be reported since public appeal by its nature require the involvement of media. This is often done in advance of real time because of the required effort and coordination with media. Therefore, public appeal is more a cautionary action driven by anticipated conditions, and not actual conditions in real time. Given the nature of the appeal and the involvement of the media, there is sufficient information provided to NERC and the concerned government agencies, making a separate report is thus redundant. f. The Event Type "Firm load shedding resulting from a BES Emergency": the basis for the reporting threshold, i.e., 100 MW, etc. has not been provided. We would appreciate the SDT providing the technical basis for this threshold. g. In Attachment 1, the event "Unplanned BES control center evacuation" applies to RC, BA, and TOP. If the evacuated control center belongs to a TOP, the TOP should have the obligation to report this, and not the RC or BA, which could be one reading of this. Consistent with the SDT's use of the word "its" for the second, third, and fourth events listed in Attachment 1 to signify that only the entity experiencing the event has the reporting responsibility, SRC recommends changing the event type description in this case to "Unplanned evacuation of its BES control center." Similarly, SRC recommends changing the next two event type descriptions to address this same issue, so that they read "Complete loss of Interpersonal Communication capability at its BES control center" and "Complete loss of monitoring or control capability at its BES control center."
Response
Thank you for your response regarding Public Appeal for load reduction to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. And continuity of the BES is intended as to remain interconnected. Thank you for your response regarding System-wide voltage reduction, the updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. It is the intent of the EOP SDT that the TOP only reports System-wide voltage reduction events. The intent is for TOP to report and initiate System-wide voltage reductions. The SDT developed this Rationale for the above;"System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction." Thank you for your comment on Public appeal. The EOP SDT agrees and has updated the Event Type to read: "Public appeal for load reduction resulting from a BES Emergency." The MW threshold is unchanged from EOP-004-3.

Attachment 1: Thank you for your comments regarding changing event type descriptions to add the word “its” to signify that only the entity experiencing the event has the reporting responsibility. The EOP SDT agreed with your comment and has made the conforming changes to Attachment 1, as well as to Attachment 2.	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Comment	

NV Energy supports the comments made by MRO-NERC Standards Review Forum:

Suggestion: Delete or clarify the Transmission loss Event Type in Attachment 1.

Rationale: Conflicting Event Analysis Program guidance, NERC Glossary definitions, and dispersed generation combine to make this Event Type confusing and challenging to evaluate within reporting timelines, subject to minimal impact, and requiring TOP’s to have greater visibility of generation resources than they possess.

Conflicting Guidance

Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design.

NERC Addendum for EAP Category 1a Events, footnote 2, page 2, explains “contrary to design”: “If a single line fault results in the faulted line tripping along with two other lines misoperating and tripping, that is three elements outaged due to a common disturbance, contrary to design. That would be a qualified event.” Likewise, page 3 states “Protection system misoperations are considered contrary to design.” We can therefore conclude that protection system operations that operate as designed are not misoperations and not contrary to design.

This is so obvious that it shouldn’t need to be pointed out here, except that the EAP Addendum contradicts this understanding of protection system operations with respect to breaker failures. In an attempt to collect circuit breaker failure data “through the EA process to facilitate identification of trends with regards to circuit breaker failures… facilities that are tripped due to breaker failure are counted as facilities outaged in determining categorization” regardless of whether that tripping is caused by the correct operation of protection systems. Examples 5 and 6 explicitly state that lines outaged by correct operation of protection systems are to be counted “since it was a breaker failure.”

While a guidance document can circumvent the plain meaning of "contrary to design" for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4 reliability standard. This results in differing criteria for evaluating which lost/outaged BES Elements/Facilities count towards the three-element threshold.

Includes Minimum Impact Losses

The NERC Glossary definitions of Elements and Facilities specifically list generators as examples. BES Elements and BES Facilities include BES generators. With the revision of the BES definition, Inclusion I4 defines each and all individual dispersed power producing resources as individual BES facilities once they aggregate to greater than 75 MVA and are connected at a voltage of 100 kV or above.

By definition, every outage, contrary to design, of three or more BES wind turbines or solar cells caused by a common disturbance must be reported as a Transmission loss event under EOP-004, even though the loss is labeled as Transmission, contains no transmission elements, and does not meet the threshold for reporting a generation loss.

Blurs Event Types

Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Generation loss has BA reporting loss of MW. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss. This blurs the line between Event Types, obligating the TOP to make determinations to file an Event Report each and every time 3 or more BES wind turbines or solar cells and/or a combination thereof with transmission elements that are lost contrary to design due to a common disturbance. The blurred event types and previously identified conflicting guidance is not conducive to a 24 hour reporting requirement.

TOP's are unlikely to have this level of visibility into wind/solar farms, necessitating GOP's to report the loss of these BES Elements to their TOP, so the TOP, as the Responsible Entity, can submit the report. The TOP should not have the responsibility of reporting event types for generator disturbances.

Suggested Remedy

Delete the Transmission loss Event Type from Attachment 1. Events can and should be analyzed under EAP. The EAP is the preferred method as there is collaboration between the reporting entity and the Regional Entity. The data is collected by the RE and NERC and can be analyzed appropriately and lessons learned developed.

Alternatively, clarify the Transmission loss Threshold for Reporting as follows:

"Unexpected loss within its area, contrary to design, of three or more BES Elements (transmission lines or transformers) caused by a common disturbance (excluding successful automatic reclosing, and as-designed protection system operations for the initiating disturbance).

By explicitly stating "BES transmission lines and transformers" we exclude generators as well as the Elements (circuit breakers, busses, and shunt and series devices) that the EAP Addendum says do not need to be included. Adding "as-designed protection system operations" as an exclusion reinforces and reiterates the limitation of losses to those "contrary to design." The qualifier "for the initiating disturbance" prevents a TOP from claiming that lines tripping on zone 3 relaying for a slow or stuck breaker is operating "as-designed."

Page 12 of 16 , Row 6

Prior to the implementation of COM-001-2 an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provided for actions to be taken for the loss of Interpersonal Communications. We suggest that the "Complete" loss of voice communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event.

Suggested Change:

Complete loss of Interpersonal Communication and Alternate Interpersonal Communication capability at a BES control center.

Response

Transmission loss: The SDT appreciates your comment about removing Transmission Loss from Attachment 1 but after many discussions the SDT felt there was still a need for this reporting requirement. Threshold changes: "Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing)."
EOP-004 Attachment 2 and OE-417 are mandatory reporting forms; whereas, EAP reporting is not mandatory.

The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility." The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications."

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project	
Answer	No

Comment

1. With regard to Attachment 1, the majority of our comments agree with the proposed changes. However, there are a few event categories that need to be clarified.
2. We disagree with the deviation from NERC Glossary Terms for the complete loss of monitoring or control capability at a BES control center. We recommend that the SDT choose the NERC-defined term "Control Center" instead of the current proposal as lower-case "control center." The NERC glossary definition would meet the criteria because this event category applies to the RC, BA, and TOP.
3. We question the removal of the RC reporting IROL violations or SOL violations on WECC Major Transfer Paths. This is a risk to reliability and NERC should be notified with an event report.
4. We also question the assignment of the RC, BA, and TOP to have reporting responsibility for Firm load shedding (> 100 MW) resulting from a BES Emergency. We are not sure if this assignment of three functions provides clarity. Are there any additional benefits to reliability for having all three entities be required to report a single load shedding event? We would like the SDT to clarify if there is an option for applicable registered entities to receive credit for reporting if one of the entities involved in a load shedding event reports on their behalf. The ability to file a report for multiple entities that are party to a single load shedding event would alleviate the burden of having to submit multiple reports for a single event.
5. We question the assignment of the BA as being solely responsible for reporting public appeals for load reduction, because some BA Areas (such as MISO or SPP) are too large for the BA to initiate such appeals. We ask the SDT to consider assigning the task to the TOP.
6. We agree with the current proposal to remove the DP from being required to report any automatic firm load shedding (> 100 MW), as this is covered by the BA, RC, and TOP.
7. Finally, we agree with the SDT that assigning the TOP as solely responsible for reporting system-wide voltage reduction (of 3% or more) to maintain the continuity of the BES provides more clarity regarding the reporting responsibilities.

Response

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity

with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers. The EOP SDT recommended removal of IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) due to the relatively low number of reports for EOP-004 because of the requirements in the TOP standards; TOP-001-3, Requirement R12 becomes effective 4/1/17 and it requires self-report if Tv is exceeded; and TOP-007-WECC-1 pending retirement. For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity. EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. Thank you for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	
Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design; however with differing definitions. EAP defines "BES Facility" and EOP-004 defines "BES Element". EOP-004 reporting threshold for loss of three elements uses "BES Elements". The BES definition includes generators, the EOP reporting for the unexpected loss is for the TOP. This is confusing on how to count elements and how the TOP is to get notification of loss of generator elements to report. Actually the TOP should not be required to do so. Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss. In addition, we are finding that the application of the EAP definition/process is being applied to EOP-004 reporting. While an EAP guidance document can circumvent the plain meaning of "contrary to design" for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4	

reliability standard. This results in differing criteria for evaluating which lost/outage BES Elements/Facilities count towards the three-element threshold and an application that ignores the Standards approval process in the NERC Rules of Procedure. The EAP process has examples for application, provides for collaboration between the entity and the regional entity provides for categorization for the NERC/FERC process and eventual lessons learned. As noted, the EOP-004 reporting item is confusing (and not correct) by definition and by application. The EOP line item for Transmission Loss needs to be eliminated in favor of the better defined and applied EAP process. We also request that the category for 'Loss of Interpersonal Communication Capability' be clarified to state that the threshold requires loss of both Primary and Alternative Interpersonal Communication Capability. We believe that is the intent of the threshold, but with the language now in COM-001-2 using 'primary and Alternative Interpersonal Communication', we believe the addition would make it as clear as possible. As currently stated, it requires an interpretation as to whether it means complete loss of 'just' Primary or both. Such as: Complete loss of **both primary and Alternative** Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more. The category for loss of offsite power to a nuclear generator could be better aligned with the EAP. The EAP refers to a 'LOOP event' which could be referenced here to provide consistency. We also recommend that the Nuclear Plant Generator Operator be the responsible entity for reporting instead of the TO or TOP.	
Response	
Thank you for your comment. The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility." The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications." The EOP SDT has added loss of off-site power"(LOOP)."	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	No
Comment	

Kansas City Power and Light Company endorses and incorporates by reference Nebraska Public Power District's response in opposition to Question 3.

In addition, we offer the following:

BES Emergency: There is inconsistent use of the NERC Glossary Term, "BES Emergency." We can only speculate as to the SDT's intent. For example, removing the term is basically removing the qualifier and expanding the applicability of the event. The opposite would be true, limiting the applicability, by including the term. We would be interested in understanding the SDT's intent for determining inclusion or exclusion of the term, BES Emergency.

Capitalization: As noted in our Question No. 1 comments, the words "control center" are used in Attachments. Since the term, "Control Center," is an approved NERC Glossary Term, we suggest it be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of "control center."

Response

Thank you for your comments. The EOP SDT's intent in "BES Emergency" is to differentiate between a localized event and event that would affect the BES; therefore, the impact of the BES Emergency is the trigger for reporting. The Purpose in the EOP-004 standard is: "**Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."
The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.

Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	No

Comment

AECI agrees with the revisions to Attachment 1. However, AECI requests the SDT to revise the term BES control center. Control Center is already defined in the NERC Glossary of Terms and should be used in lieu of BES control center throughout the attachment.

Response	
Thank you for your comment. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Lynda Kupfer - Puget Sound Energy, Inc. - 5	
Answer	No
Comment	

I wasn't given the option to skip the survey and support another's response after voting negatively for EOP-004-4. Please accept this response. PSE supports IESO, OGE and LG&E comments.

We do not agree with the following changes:

1. For the Event Type “Public appeal for load reduction”: It is unclear what “maintain the continuity of the BES” really means. By “continuity”, does it mean “integrity of the BES” or “continuity of supply”? This needs to be revised to be more specific and to improve clarity.

2. Assigning the TOP to be the responsible entity for reporting system wide voltage reduction

Voltage reduction is intended to reduce system demand to address capacity deficiency. While the TOP may be the entity to actually direct actions (e.g. transformer tap changes) to achieve voltage reduction, the BA is the entity that decides and gives the direction to implement the system wide voltage action/measure to achieve a reduction in system demand. We recommend changing it to the BA. Also, similar to the comment above, it is unclear what “maintain the continuity of the BES” really means. By “continuity”, does it mean “integrity” or “continuity of supply”? Either way, we do not see the value added or the necessity of the having this qualifier. We suggest to revise the Event Type to “System wide voltage reduction” or where a qualifier is deemed to add value, change it to “System wide voltage reduction to maintain load supply” or “to meet system demand”.

3. The Event Type “Firm load shedding resulting from a BES Emergency”: the basis for the reporting threshold, i.e., 100 MW, etc. has not been provided. We would appreciate the SDT providing the technical basis/justification other than just because it existed before.

Leonard Kula, Independent Electricity System Operator, 2, 8/30/2016

LG&E and KU Energy (“LG&E/KU”) appreciates the opportunity to submit this comment for the Standard Drafting Team's consideration.

The reportable event type “Complete loss of Interpersonal Communication capability at a BES control center” has a threshold for reporting of “Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more.” LG&E/KU proposes the event type be rewritten as “Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability at a BES control center”. Furthermore, LG&E/KU proposes changing the threshold for reporting to read “Complete loss of Interpersonal Communication (including Alternative Interpersonal Communication) capability affecting a staffed BES control center for 30 continuous minutes or more.”

LG&E and KU Energy, Segment(s) 3, 5, 6, 5/26/2016

Response

Thank you for your response regarding Public Appeal for load reduction to maintain continuity of the BES. The updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417. And continuity of the BES is intended as to remain interconnected.
Voltage reduction: EOP-011-1 and the VAR standards puts the requirements of the voltage reduction (transmission system reconfiguration) on the TOP; therefore, the BA should not be added to the reporting category.
The MW threshold is unchanged from EOP-004-3.
The EOP SDT has added “Alternative Interpersonal Communications.”

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	Yes

Comment

Under Event Type “BES Emergency resulting in voltage deviation on a Facility” the threshold should be updated to include the word ‘exceeding’. The threshold should read ‘A voltage deviation exceeding +/- 10% of nominal voltage sustained for >/= 15 continuous minutes.”

Response	
Thank you for your comment. The EOP SDT made the following change for clarity in response to your comment: “A voltage deviation of =/> ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.”	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Comment	
In Attachment 1, the removal of the TOP as a responsible reporting Entity for "Damage or destruction of its Facility" and "Physical threats to its Facility" potentially causes concern. This could be problematic for facilities that are owned by one entity but operated by another. We request that the SDT have continued discussion around these types of scenarios and consider putting the TOP back in as a responsible Entity.	
Response	
Thank you for your comment. The EOP SDT believes in many cases that the GO/GOP and TO/TOP are both the same owner of the Facility. But there are times when the GOP function is not done by the GO, therefore we felt the GOP also needed to be included in the reporting since they could also be the entity ‘recognizing the event’. The EOP SDT is continuing to try to stream line reporting to specific entities and those entities that own Facilities. The EOP SDT reviewed the NERC Reliability Functional Model, which defines the TOP as the functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area. Therefore, the EOP SDT agrees with your comment and has added the TOP back in as a Responsible Entity.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Comment	
Event Type: Public appeal for load reduction: There may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend leaving the “Entity with Reporting Responsibility” as it currently reads: **Initiating entity is responsible for reporting.** (Attachment 1, Page 10, 4th Row)	

Event Type: Firm load shedding resulting from a BES Emergency: We recommend leaving the "Entity with Reporting Responsibility" as it currently reads: **Initiating entity is responsible for reporting.** (Attachment 1, Page 11, 1st Row) Event Type: Generation loss; We recommend the following statement for "Threshold for Reporting:" **Reporting of generation loss would be used to report Forced Outages, not weather patterns or fuel source unavailability for these resources.** (Attachment 1, Page 12, 2nd Row)		
Response		
EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. The entity that sheds load from a BES Emergency is responsible for reporting. Given there are regional and registration differences, the intent of the EOP SDT is for one of the entities to have the reporting responsibility. For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity. Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability and determined that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.		
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority		
Answer	Yes	
Comment		
At times there may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend replacing "BA" with "Initiating BA or TOP." The event types with multiple applicable entities such as, "Firm load shedding resulting from a BES Emergency", "Uncontrolled loss of firm load resulting from a BES Emergency", and "System separation (islanding)" will most likely have the same event reported multiple times if the BA, TOP or RC are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type, "Firm load shedding resulting from a BES Emergency" to "Initiating RC, BA, or TOP". We recommend changing the Entity with Reporting Responsibility for the Event Type, "Uncontrolled loss of firm load resulting from a BES Emergency" to just the BA. We recommend changing the Entity with Reporting Responsibility for the Event Type,		

"System separation (islanding)" to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported. For Event Type *Uncontrolled loss of firm load resulting from a BES Emergency,* the MW lost amount may be better representative of an impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.	
Response	
EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity. Thank you for your response regarding Uncontrolled loss of firm load, the updated event type and reporting threshold closely aligned EOP-004-4 with the U.S. Department of Energy OE-417.	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Comment	
Add the word 'staffed' to the threshold column for 'Complete loss of monitoring or control at a BES control center' so that it is consistent with the Event Type above it which states: Complete loss of Interpersonal Communication capability affecting a **staffed** BES control center for 30 continuous minutes or more.	
Response	
Thank you for your comments. The EOP SDT has added "Alternative Interpersonal Communications." The EOP SDT agrees with your comment and has added "staffed" to the event types and thresholds.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	

Answer	Yes
Comment	

Consider adding ‘its’ to unplanned evacuation of (its) BES control center for consistency.

Consider adding ‘Alternate Interpersonal Communications’ in addition to complete loss of Interpersonal Communications to add clarity.

Consider adding ‘staffed’ to both event type and threshold for loss of control center Interpersonal Communications (p.12 of 16) for consistency.

Response

Thank you for your comments.
The EOP SDT agrees with your comment to add “its” and made the conforming change.
The EOP SDT agrees with your comment and has added “Alternative Interpersonal Communications.”
Staffed: Staffed has been added to the event types and thresholds.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	Yes
Comment	

Suggestion: Delete or clarify the Transmission loss Event Type in Attachment 1.

Rationale: Conflicting Event Analysis Program guidance, NERC Glossary definitions, and dispersed generation combine to make this Event Type confusing and challenging to evaluate within reporting timelines, subject to minimal impact, and requiring TOP’s to have greater visibility of generation resources than they possess.

Conflicting Guidance

Both EOP-004-4 Transmission loss Threshold for Reporting and EAP Category 1a apply to unexpected loss/outage of three or more BES Elements/Facilities contrary to design.

NERC Addendum for EAP Category 1a Events, footnote 2, page 2, explains “contrary to design”: “If a single line fault results in the faulted line tripping along with two other lines misoperating and tripping, that is three elements outaged due to a common disturbance, contrary to design. That would be a qualified event.” Likewise, page 3 states “Protection system misoperations are considered contrary to design.” We can therefore conclude that protection system operations that operate as designed are not misoperations and not contrary to design.

This is so obvious that it shouldn’t need to be pointed out here, except that the EAP Addendum contradicts this understanding of protection system operations with respect to breaker failures. In an attempt to collect circuit breaker failure data “through the EA process to facilitate identification of trends with regards to circuit breaker failures… facilities that are tripped due to breaker failure are counted as facilities outaged in determining categorization” regardless of whether that tripping is caused by the correct operation of protection systems. Examples 5 and 6 explicitly state that lines outaged by correct operation of protection systems are to be counted “since it was a breaker failure.”

While a guidance document can circumvent the plain meaning of “contrary to design” for the voluntary data-gathering EAP, it cannot do so for the EOP-004-4 reliability standard. This results in differing criteria for evaluating which lost/outaged BES Elements/Facilities count towards the three-element threshold.

Includes Minimum Impact Losses

The NERC Glossary definitions of Elements and Facilities specifically list generators as examples. BES Elements and BES Facilities include BES generators. With the revision of the BES definition, Inclusion I4 defines each and all individual dispersed power producing resources as individual BES facilities once they aggregate to greater than 75 MVA and are connected at a voltage of 100 kV or above.

By definition, every outage, contrary to design, of three or more BES wind turbines or solar cells caused by a common disturbance must be reported as a Transmission loss event under EOP-004, even though the loss is labeled as Transmission, contains no transmission elements, and does not meet the threshold for reporting a generation loss.

Blurs Event Types

Transmission loss and Generation loss are distinct Event Types with differing Reporting Thresholds appropriate to the Event Type and Responsible Entity. Generation loss has BA reporting loss of MW. Transmission loss has TOP reporting number of BES Elements, presumably transmission elements. As written, BES Generators are not excluded as BES Elements for Transmission loss. This blurs the line between Event Types, obligating the TOP to make determinations to file an Event Report each and every time 3 or more BES wind turbines or solar cells and/or a combination thereof with transmission elements that are lost contrary to design due to a common disturbance. The blurred event types and previously identified conflicting guidance is not conducive to a 24 hour reporting requirement.

TOP's are unlikely to have this level of visibility into wind/solar farms, necessitating GOP's to report the loss of these BES Elements to their TOP, so the TOP, as the Responsible Entity, can submit the report. The TOP should not have the responsibility of reporting event types for generator disturbances.

Suggested Remedy

Delete the Transmission loss Event Type from Attachment 1. Events can and should be analyzed under EAP. The EAP is the preferred method as there is collaboration between the reporting entity and the Regional Entity. The data is collected by the RE and NERC and can be analyzed appropriately and lessons learned developed.

Alternatively, clarify the Transmission loss Threshold for Reporting as follows:

"Unexpected loss within its area, contrary to design, of three or more BES Elements (transmission lines or transformers) caused by a common disturbance (excluding successful automatic reclosing, and as-designed protection system operations for the initiating disturbance).

By explicitly stating "BES transmission lines and transformers" we exclude generators as well as the Elements (circuit breakers, busses, and shunt and series devices) that the EAP Addendum says do not need to be included. Adding "as-designed protection system operations" as an exclusion reinforces and reiterates the limitation of losses to those "contrary to design." The qualifier "for the initiating disturbance" prevents a TOP from claiming that lines tripping on zone 3 relaying for a slow or stuck breaker is operating "as-designed."

Page 12 of 16 , Row 6

Prior to the implementation of COM-001-2 an Event under EOP-004-2 was the complete loss of voice communications. With the restructuring of COM-001-2 to include the defined terms Interpersonal Communications and Alternate Interpersonal Communications, the Standard provided for actions to be taken for the loss of Interpersonal Communications. We suggest that the "Complete" loss of voice

communications is now the loss of Interpersonal Communications and Alternate Interpersonal Communications and which rises to the level of reporting for an EOP-004 event. Suggested Change: Complete loss of Interpersonal Communication and Alternate Interpersonal Communication capability at a BES control center.	
Response	
Transmission loss: The SDT appreciates your comment about removing Transmission Loss from Attachment 1 but after many discussions the SDT felt there was still a need for this reporting requirement. Threshold changes: "Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing)." EOP-004 Attachment 2 and OE-417 are mandatory reporting forms; whereas, EAP reporting is not mandatory. The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility." The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications."	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Comment	
On Attachment 1 recommend rewording Event Type "Complete Loss of Interpersonal Communications capability at a BES Control Center" to be "Complete loss of Interpersonal Communication and Alternative Communication capability at a staffed BES Control Center". The COM-001-2 Standard addresses loss of Interpersonal Communication capability.	
Response	
Thank you for your comment. The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications."	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Comment	

With regard to Attachment 1, a change has been made with respect to the Reporting Responsibility for damage or destruction and physical threats to a facility. Accountability has been moved to the Transmission Owner (i.e. Transmission Operator and Balancing Authority have been removed). If this is deemed to be an Owner versus Operator responsibility, why is the same not true for the GO/GOP functions?	
Response	
Thank you for your comment. The EOP SDT believes in many cases that the GO/GOP and TO/TOP are both the same owner of the Facility. But there are times when the GOP function is not done by the GO, therefore we felt the GOP also needed to be included in the reporting since they could also be the entity 'recognizing the event'. The EOP SDT is continuing to try to stream line reporting to specific entities and those entities that own Facilities. The EOP SDT reviewed the NERC Reliability Functional Model, which defines the TOP as the functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area. Therefore, the EOP SDT agrees with your comment and has added the TOP back in as a Responsible Entity.	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Comment	
Hydro One Networks is satisfied with attachment 1. For "Transmission Loss" event type please consider changing "Element" to "Facility" in the description of the Threshold for Reporting (as category 1.a. in the EAP).	
Response	
Thank you for your comment. The EOP SDT agrees with your comment and has made the conforming change from "Element" to "Facility".	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Comment	
Comemnts as follows:	

1. At times there may be a need for a Transmission Operator (“TOp”) to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. Entergy recommends replacing “BA” with initiating Balancing Authority (“BA”) or TOp.

2. The event types with multiple applicable entities such as, “Firm load shedding resulting from a BES Emergency”, “Uncontrolled loss of firm load resulting from a BES Emergency” and “System separation (islanding)” will most likely have the same event reported multiple times if the BA, TOp, or Reliability Coordinator (“RC”) are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type. “Firm load shedding resulting from a BES Emergency” to “Initiating RC, BA, or TOp”. We recommend changing the Entity with Reporting Responsibility for Event Type, “Uncontrolled loss of firm load resulting from a BES Emergency” to just BA. We recommend changing the Entity with Reporting Responsibility for the Even Type, “System separation (islanding)” to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.

3. Under Event Type “Uncontrolled loss of firm load resulting from a BES Emergency” the MW lost amount may be better representative of an impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.

4. For Event Type Complete Loss of Interpersonal Communications capability at a BES control center, consider also adding Alternative Communication Capability. This will differentiate the event form a COM standard requirement. On event type include the word “staffed” to match working in the Threshold section. Entergy does not agree that the loss of primary/use of backup control center should be a reportable event. Please provide clarification of this point.

Response

Thank you for your comments.
EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA’s Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004.
For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.
The MW threshold is unchanged from EOP-004-3.
The EOP SDT agrees with your comment and has added “Alternative Interpersonal Communications.”

The EOP SDT agrees with your comment and has added “staffed” to the event types and thresholds.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
Hydro One Networks Inc. is satisfied with Attachment 1. However, for “Transmission Loss” event type, please consider changing “Element” to “Facility” in the description of the Threshold for Reporting (as per Category 1.a. in the EAP).	
Response	
Thank you for your comment. The EOP SDT agrees with your comment and has made the conforming change from “Element” to “Facility.”	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
*Regarding Attachment 1: Reportable Events, BPA recommends clarifying the public appeal for load reduction applicable to the BA by specifying "load reduction" with "**BA** load reduction".*	
Response	
EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA’s Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004.	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Comment	

a. At times there may be a need for a Transmission Operator ("TOp") to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. Entergy recommends replacing "BA" with initiating Balancing Authority ("BA") or TOp.

b. The event types with multiple applicable entities such as, "Firm load shedding resulting from a BES Emergency", "Uncontrolled loss of firm load resulting from a BES Emergency" and "System separation (islanding)" will most likely have the same event reported multiple times if the BA, TOp, or Reliability Coordinator ("RC") are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type. "Firm load shedding resulting from a BES Emergency" to "Initiating RC, BA, or TOp". We recommend changing the Entity with Reporting Responsibility for Event Type, "Uncontrolled loss of firm load resulting from a BES Emergency" to just BA. We recommend changing the Entity with Reporting Responsibility for the Even Type, "System separation (islanding)" to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.

c. Under Event Type "Uncontrolled loss of firm load resulting from a BES Emergency" the MW lost amount may be better representative of an impact to a BA if it was a specific percentage of peak load. The current threshold goes from a 10% of total load value for a 3000 MW BA to less than 1% of total load for the bigger BAs.

d. For Event Type Complete Loss of Interpersonal Communications capability at a BES control center, consider also adding Alternative Communication Capability. This will differentiate the event form a COM standard requirement. On event type include the word "staffed" to match working in the Threshold section. Entergy does not agree that the loss of primary/use of backup control center should be a reportable event. Please provide clarification of this point.

Response

EOP-011-1 puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004.
For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.
The MW threshold is unchanged from EOP-004-3.
The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications."
The EOP SDT agrees with your comment and has added "staffed" to the event types and thresholds.

Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	
Answer	Yes

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Dave Thomas - Peak Reliability - 1	
Answer	Yes
Erika Doot - U.S. Bureau of Reclamation - 5	
Comment	
Reclamation agrees with the drafting team's proposal to eliminate duplicative reporting requirements. However, Reclamation suggests that reporting should only be required for "complete loss of ***all*** interpersonal communication capabilities" at staffed control centers. Reclamation requests that the drafting team update this line item because as written, the update could require reporting of the loss of any communication system even when a fully functioning backup system is utilized.	
Response	

Thank you for your comment. The EOP SDT agrees with your comment and has added "Alternative Interpersonal Communications." The EOP SDT agrees with your comment and has added "staffed" to the event types and thresholds.

4. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	No
Comment	
AECI requests the SDT to revise the term BES control center. Control Center is already defined in the NERC Glossary of Terms and should be used in lieu of BES control center throughout the attachment.	
Response	
Thank you for your comment. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	

Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	No
Comment	
Reclamation suggests that reporting should only be required for "complete loss of ***all*** interpersonal communication capabilities" at staffed control centers. Reclamation requests that the drafting team update this line item because as written, the update could require reporting of the loss of any communication system even when a fully functioning backup system is utilized.	
Response	

Thank you for your comment. The EOP SDT has added "Alternative Interpersonal Communications."	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	No
Comment	
For consistency with our comment on Attachment 1, "Public Appeal" and "System-wide voltage reduction" should remain under the "BES Emergency" heading.	
Response	
Thank you for your comment regarding Public Appeal. The updated event type and reporting threshold closely aligned EOP-004-4 reporting requirements with the U.S. Department of Energy OE-417 form.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra	
Answer	No
Comment	
In the header of the Attachment 2, add "select Option 1" after the voice number provided for the submittal of the form. Similar as in the Attachment 1. Under section 4, there are two instances of "Unplanned BES control center evacuation." Remove the first instance so that the order of the list in Attachment 2 matches the Attachment 1. Attachment 2 is not required for use and it should be stated in Attachment 2 that it is a guidance document, not tied to compliance. The change to attachment 2 implies that it is a compliance obligation to supply a completed Attachment 2 to all entities listed in the Event Reporting Operating Plan. This is not the case as written in R2 and a correction to either Attachment 2 or the requirement language should be made.	
Response	
Thank you for your comments. The EOP SDT has revised Attachment 2 to include: "Option 1". The duplicate 'Unplanned BES control center evacuation' from the Event Identification and Description in Attachment 2 has been deleted.	

Measure M2 lists the Attachment 2 form as one type of evidence that can be used for Requirement R2. Requirement R2 and Measure M2 confirms entities shall report events within 24 hours of recognition of meeting the event type threshold. NERC EOP-004 and DOE OE-417 have separate reporting timeline requirements. In lieu of the EOP-004, Attachment 2, NERC will accept the DOE-OE-417 form as type of evidence for Measure M2. **“Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2”** has been added back into Attachment 1 of the standard. Measure M2 also indicates Attachment 2 can be used as evidence for event reporting.

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Comment	
“Unplanned BES control center evacuation” is listed twice on Attachment 2; i.e. as part of the original form (p. 16) and as a new addition (p. 15). Recommend the bullet on p. 16 be retained (as it mirrors the order found in Attachment 1) and the duplicative bullet on p. 15 deleted.	
Response	
Thank you for your comment. The duplicate 'Unplanned BES control center evacuation' from the Event Identification and Description in Attachment 2 has been deleted.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Comment	
Texas RE recommends aligning the event types in Attachment 1 with the tasks in Attachment 2. For example, Texas RE noticed the event types “System-wide voltage reduction to maintain the continuity of the BES” and “Firm load shedding resulting from a BES Emergency” are included in Attachment 1, but not listed in Attachment 2.	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Comment	
CenterPoint Energy recommends that the “Tasks” in Attachment 2 Event Reporting Form align with the Event Types in Attachment 1 if revised by the SDT.	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Comment	
No suggested changes to the text that has been modified. In addition, suspious activity must be listed. Currently, suspicious activity would fall under physical threat to a facility. Taking pictures or flying a drone over a facility could fall under suspicious activity but not always under a physical threat. Suggest adding a suspicious activity line with a check box.	
Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Response	
Thank you for your comment. To be consistent with Attachment 1, the EOP SDT believes that suspicious activity should be covered under the “Physical threats to its Facility” Task on Attachment 2 and should not be added to Attachment 2 as separate Task.	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Comment	
Any changes to Event Type from comments above carry down to attachment 2 as well.	
Response	

Thank you for your comment. The EOP SDT has updated Attachment 2 task list.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes

Comment

Capitalization: As previously noted in our comments, the words "control center" are used in multiple places. Since the term "Control Center" is an approved NERC Glossary Term, we suggest it should be capitalized. If the intent of the SDT was not to use the Glossary Term, Control Center, additional definition and parameters are needed to provide clarity to the meaning of control center.

Response

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project

Answer	Yes

Comment

1. We question if there are any compliance impacts if an entity reports within the required timelines, but uses the previous version of the event reporting form. There are several modifications to Attachment 1. We would like the SDT to clarify whether reporting an event on the previous version of the form would be a violation. This seems to be a potential administrative burden, both for the entities submitting the information, and the Regional Entities and NERC that receive the event reports.
2. We recommend implementing a reporting software tool on the NERC website, which has the capabilities to notify applicable Regional Entities and the DOE of an event. This would alleviate the need to include Attachment 2 as part of the standard and would further streamline the process with a centralized portal for all entities to submit event reports. We ask the NERC standards developer assigned to this project to share this comment with NERC IT department to see if this type of solution is viable.

Response	
The EOP SDT has an Implementation Plan for the revised standard; therefore, it would give entities time to update their reporting process to include the newly-updated Attachment 2. The violation question could be submitted to your Regional Entity. The EOP SDT is working with the DOE to have all EOP-004 event categories listed on the OE-417 reporting form that is available online; therefore, this could be the one place for EOP-004 and DOE reporting to be done.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Comment	
Hydro One Networks Inc. is satisfied with Attachment 2. Please also note that the check box item, "Unplanned BES control center evacuation", is duplicated.	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Comment	
Comment: Any changes to Event Type from comments above should carry down to Attachment 2 as well.	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Comment	

Hydro One Networks is satisfied with attachment 2. The check box item “Unplanned BES control center evacuation” is duplicated	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
Add “, select Option 1” to the voice number as per the note in Attachment 1.	
Response	
Thank you for your comment. “Option 1” has been added in Attachment 2	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Comment	
In the introductory section of the form, the SDT could consider adding the qualifier ‘applicable’ to organizations to clarify that the reporting requirement is not to all the enumerated organizations: “**Also submit to other applicable organizations per Requirement R1 “… (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or Applicable Governmental Authority).”**	
Response	
The EOP SDT has added ‘applicable’ to “submit to other [applicable] organizations…” in Attachment 2. Thank you for this suggestion.	
Quintin Lee - Eversource Energy – 1	
Answer	Yes
Comment	

Under section 4, there are two instances of 'Unplanned BES control center evacuation.' Remove the first instance so that the order of the list in Attachment 2 matches the Attachment 1.	
Response	
Thank you for your comments. The EOP SDT has updated Attachment 2 task list.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Comment	
Refer to comments for #3 above. Attachment 2, Page 15, 4th bullet, "Unplanned BES control center evacuation" is duplicated on Page 16, 5th bullet.	
Response	
Thank you for your comment. The EOP SDT has updated Attachment 2 task list.	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Comment	
"PSEG is pleased to have the opportunity to comment and is in general agreement with the revisions to the standard. The EOP-004 form (Attachment 2) states "Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)." We recommend replacing the term "submit" with "report", or determine if reporting via a different form would meet compliance. Law enforcement, in particular the Regional Operations centers (ROIC) in New Jersey and Connecticut, have a different form (Suspicious Activity Reporting or SAR form) that is used to report events. Therefore, replacing the term "submit" with "report" would aid in harmonizing reporting EOP-004 reporting requirements with processes for reporting events to law enforcement."	
Response	

Thank you for your comment. The EOP SDT finds the language is clear as written.	
Dave Thomas - Peak Reliability - 1	
Answer	Yes
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Johnny Anderson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Matt Stryker	

Answer	Yes
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Robert Tallman - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	

Answer	Yes
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Marcus Freeman - ElectriCities of North Carolina, Inc. - 4 - SERC	
Answer	Yes
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes

5. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - NA - Not Applicable - SPP RE	
Answer	
Comment	
OGE is concerned that the SDT has not looked at some of the CIP standards and how it is tied to the requirements in EOP-004. Currently, there appears to be redundant reporting requirements between CIP-008 and EOP-004. For example, CIP-006 Standard, Part 1.5 states that the Physical Security Plan must describe issuance of an alarm or alert in response to the unauthorized access into or through a Physical Security Access Point, and the alarm or alert must be communicated as identified in the Entity's CIP-008 BES Cyber Security Incident Response Plan. The Response Plan includes reporting of the event to the appropriate agencies (including NERC and DOE). This ties in to the Physical Threats event type in Attachment 1 of EOP-004-4. We believe there is some overlap or at least touchpoints between the two standards, although the CIP standards are focused on protection of the cyber assets, it still includes physical access to these cyber assets. We are requesting the SDT to review the latest versions of the CIP standards (specifically CIP-006 and CIP-008) to ensure there is no overlapping or redundant reporting requirements.	
Likes 1	Puget Sound Energy, Inc., 1, Rakowsky Theresa
Response	
Thank you for your comment and the EOP SDT discussed that there is no specific requirement in CIP-006 to report any physical threats to a Facility. CIP-006 says to refer to CIP-008 Cyber Security response plan. The Cyber Security response plan requires notification to E-SIAC only, which not related to EOP-004 reporting.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	
Comment	
There should be further revisions to Attachment 1. Specifically, "suspicious device or activity" is ambiguous. Further clarification on "suspicious activity" is needed. For example, does this include photography near a Facility? Also, Attachment 1 should specifically cover	

cyber related suspicious activity – for example, solicitation attempts or phishing calls at Facilities. There should also be instruction on what an Entity should do if they later realize the incident was NOT suspicious – for example, a prior reported incident which, after further investigation, turns out to be innocuous. The effect of using ambiguous terms and no mechanism for correcting incidents post investigation has left the industry with an output that contains more "trash" than value – many incidents that do not truly meet the definition of EOP 004 are sent out via EISAC which leads to the dilution of truly important incidents.
Response
The EOP SDT believes that "suspicious device or activity" is broad enough to include any type of abnormalities noticed. The EOP SDT also believes the entity's event reporting Operating Plan is not limited and can be detailed as needed to identify Physical threats to its Facility. If an entity determines an incident was not suspicious, they have 24 hours to report. If there is a question as to whether an incident meets reporting thresholds or not, weighing on the cautious side and reporting the event is the right thing to do.
Quintin Lee - Eversource Energy - 1
Comment
Change 'control center' to 'Control Center' throughout the document to be consistent with the NERC Glossary
Response
The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Document Name	
Comment	
N/A	

Response
Richard Vine - California ISO - 2
Comment
For all questions the California ISO supports the comments of the ISO/RTO Council Standards Review Committee
Response
Please see responses to ISO/RTO Council Standards Review Committee.
Rachel Coyne - Texas Reliability Entity, Inc. - 10
Comment
Texas RE requests the SDT provide rationale for each change made to the Standard. Texas RE would like to better understand the SDT's reasoning in the changings and how they affect reliability. Additionally, Texas RE requests rationale for the implementation plan. The Implementation Plan for the proposed EOP-004 provides that "the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority." Given that registered entities presently are required to submit event reports under the current version of EOP-004 and the revised version largely narrows the scope of such reporting activities, it is unclear why a 12-month implementation period is necessary.
Response
Thank you for your comments. The EOP SDT will be adding additional Rationale boxes to the standard, where it is appropriate to do so. The Rationale boxes are carried into the "Supplemental Material" section of the standard upon applicable governmental approval. Not all revisions to the standard would be appropriate in a Rationale box; for example, if there is a retirement of a requirement or subpart. The Mapping Document is a good source for revisions made to the standard, as well as the Rationale boxes and other supporting documents. The EOP SDT has created rationale boxes and a mapping document for this project, which will include all changes that have been made. A full redline to each last-approved standard was included on the project page during the initial comment/ballot period. The final ballot period will have final redlines to the last-approved standard.

The Implementation Plan takes into account any barriers to implementation. The EOP SDT intent for the twelve-month Implementation Plan was to give all entities an appropriate time frame for implementation.

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Comment

Please continue the effort to harmonize NERC Event Reporting requirements with DOE reporting requirements as listed on the OE-417. Currently; it is needlessly burdensome to ensure we meet reporting requirements for both NERC and DOE within specified timeframes. This is particularly difficult considering DOE's 1 or 6 hour submittal requirements and the circumstances a System Operator is likely to be faced with while attempting to submit these reports.

Ideally, DOE would defer to NERC for Event Reporting as required by EOP-004; thus alleviating the potential for separate submissions, on separate forms, with different time requirements for submittal.

Response

Thank you for your comments. With respect to DOE collaboration, the SDT has discussed with DOE changes that would be necessary to EOP-004 Attachment 1 and to OE-417 to more closely align EOP-004-4 Attachment 1 Reportable Events with events reported on OE-417. Based on those discussions and the changes proposed in this posting, the SDT and DOE have made significant progress in harmonizing reporting requirements, which would relieve many entities from having to report Reportable Events on both forms. That collaboration continues, but it is important to note that **regardless of whether OE-417 is harmonized with EOP-004-4 Attachment 1, entities will be required to report all Reportable Events as required by EOP-004-4**. The EOP SDT discussed the reporting timeframes of the OE-417 reporting with the DOE and the DOE plans to keep the 1 or 6 hour reporting timeframes for the OE-417.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Comment

Duke Energy recommends that the drafting team revisit the language used in the VSL(s) for R2. The revisions posted for R2 include the addition of the phrase *"specified in EOP-004-4 Attachment 1 to the entities specified"*. The use of *"the entities specified",* does not match up with the language used in the VSL(s) for R2 which use the verbiage "to all required recipients" when describing who an event report should be submitted to. We suggest the drafting team consider using identical language in the Requirements and complementing VSL(s).

Response
Thank you for your comment. The EOP SDT has revised the language in VSLs for Requirement R2 to align with the requirement language.
Johnny Anderson - IDACORP - Idaho Power Company - 1
Comment
No additional comments.
Response
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling
Comment
none
Response
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NextEra
Comment
Change “control center” to “Control Center” throughout the document to be consistent with the NERC Glossary.
Response
Thank you for your comment. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.

Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Comment	
Entergy recommends going to a 72 hour reporting deadline to match the final report deadline for the Department of Energy's form OE-417.	
Response	
Thank you for your comment. With respect to DOE collaboration, the SDT has discussed with DOE changes that would be necessary to EOP-004 Attachment 1 and to OE-417 to more closely align EOP-004-4 Attachment 1 Reportable Events with events reported on OE-417. Based on those discussions and the changes proposed in this posting, the SDT and DOE have made significant progress in harmonizing reporting requirements, which would relieve many entities from having to report Reportable Events on both forms. That collaboration continues, but it is important to note that **regardless of whether OE-417 is harmonized with EOP-004-4 Attachment 1, entities will be required to report all Reportable Events as required by EOP-004-4**.	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Comment	
SRC suggests one additional improvement to the baseline language. The note in Attachment 1 states that "Under certain adverse conditions (e.g. severe weather, multiple events), it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification." However, this exception doesn't appear in Requirement R2, which is the source of the reporting obligation. SRC recommends modifying Requirement R2 to explicitly recognize this exception. Also, the above-noted language in Attachment 1 lacks clarity as to exactly what sort of reporting is required when the responsible entity experiences an adverse condition and also as to when such a report must be provided. SRC suggests that, when a responsible entity experiences adverse conditions that preclude timely notification of a reportable event, the entity should be allowed to provide either verbal or written notification, and should do so as soon as practicable following the expiration of the 24-hour period for reporting the event. SRC further suggests that, if verbal notification of the event is provided, the responsible entity should submit written notification of the event as soon as practicable after providing the verbal notification. To address these concerns, SRC recommends deleting the exception described above from Attachment 1 and adding the following language at the end of R2: "However, if the Responsible Entity experiences an adverse condition (e.g., severe weather, multiple events) that prevents it from submitting an event report before the expiration of the 24-hour reporting period, it shall provide verbal or written notification of the event to the entities specified in its Operating Plan as soon as practicable thereafter. If the	

Responsible Entity provides verbal notification pursuant to this exception, it shall provide written notification of the event as soon as practicable thereafter."
Response
Thank you for your comment. In response to your comment concerning Attachment 1 lacking clarity as to exactly what sort of reporting is required when the responsible entity experiences an adverse condition and also as to when such a report must be provided, the entity needs to report on all of the event types and thresholds applicable to them, and when they cannot complete an Attachment 2 report due to adverse conditions, there is no limit as to how the entity shall otherwise notify parties per Requirement R2. This reporting could be done via verbal, email, etc. The entities event reporting Operating Plan should address these types of situations. The RSAW also contains this "Note to auditor: if the entity cannot distribute the report due to adverse conditions as specified in EOP-004-Attachment 1. The auditor should document the delay and reason for the delay. Late reporting due to these adverse conditions is not considered a non-compliance with R2."
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC
Comment
Bonneville Power Administration (BPA) recommends any reference to "BES control center" or "control center" be capitalized and replaced with "BES Control Center" or "Control Center" as a NERC defined term.
Response
Thank you for your comment. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - EOP Project
Comment

Thank you for the opportunity to comment.

Response

Dave Thomas - Peak Reliability - 1

Comment

PEAK Reliability supports these changes.

Response

Thank you for your support.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Comment

Capitalization: The Standard's Applicability section states, "…the following functional entities..."

Additionally, the Supplemental Materials, Potential Uses of Reportable Information, the words, "Functional entities" are used.

The term "Functional Entity" is a defined term in the NERC Rules of Procedure, App. 2. Since the references are to Functional Entities defined by the intent and authority under the Rules of Procedure, we suggest functional entity or entities should be capitalized.

Response

Thank you for your comment. The EOP SDT has capitalized Functional Entity.

Mark Riley - Associated Electric Cooperative, Inc. - 1

Comment

Although the implementation plan is not specifically referenced in the survey, AECI requests the SDT to revise the proposed effective date of EOP-004-4. The revisions to EOP-004-4 require procedural and reporting changes for Responsible Entities. These modifications should not take a full 12 months to implement and the industry would benefit immediately from the enhanced reporting process. AECI requests the SDT to revise the implementation plan and establish an effective date that is the first calendar quarter that is three (3) months after the date of applicable governmental authority's order approving the standard.

Response

Thank you for your comment. The Implementation Plan takes into account any barriers to implementation. The EOP SDT intent for the twelve-month Implementation Plan was to give all entities an appropriate time frame for implementation.

Jaclyn Massey - Entergy - Entergy Services, Inc. - 5

Comment

Entergy recommends going to a 72 hour reporting deadline to match the final report deadline for the Department of Energy's form OE-417.

Response

Thank you for your comment. With respect to DOE collaboration, the SDT has discussed with DOE changes that would be necessary to EOP-004 Attachment 1 and to OE-417 to more closely align EOP-004-4 Attachment 1 Reportable Events with events reported on OE-417. Based on those discussions and the changes proposed in this posting, the SDT and DOE have made significant progress in harmonizing reporting requirements, which would relieve many entities from having to report Reportable Events on both forms. That collaboration continues, but it is important to note that **regardless of whether OE-417 is harmonized with EOP-004-4 Attachment 1, entities will be required to report all Reportable Events as required by EOP-004-4**.

Mike Anctil - Los Angeles Department of Water and Power - 3

Comment

1. Event Type 2 and 3 on page 10 ("Physical threats to its Facility" and "Physical threats to its BES control center") is too broad and will require entities to file a report for any suspicious activity or device within 24 hours. In the Threshold for Reporting column of these Event Types, it would be better to eliminate "OR Suspicious device or activity at a its Facility. Do not report theft unless it degrades

normal operation of a Facility." This elimination would give entities some latitude on determining when a suspicious activity was worthy of a report.

Response
Thank you for your comment, but the EOP SDT chose to keep the threshold for reporting as it was previously written to be all-inclusive of types of physical threats.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/25/2016 – 12/08/2016
10-day final ballot	12/27/2016 – 01/10/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources

2. **Number:** EOP-005-3

3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Generator Operators

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan

5. **Effective Date:** See the Implementation Plan for EOP-005-3.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for System restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform:

(1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.

The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every 24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every 24 calendar months to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in effect since the last monitoring activity for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity, as well as one previous monitoring activity period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in effect since its last monitoring activity for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in effect since its last monitoring activity on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last monitoring activity records and all requested and submitted subsequent monitoring activity records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three of the ~~r~~equirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification. .	The Transmission Operator has failed to update and submit its revised restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				prior to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a 24-calendar-month period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator	N/A	The Transmission Operator and Generator Operator

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.		with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a 24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a 24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a t24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a 24-calendar-month period.
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~06/22/2016 – 08/08/2016~~
45-day formal comment period with additional ballot	~~08~~10/~~30~~25/2016 – ~~10~~12/~~14~~08/2016
10-day final ballot	~~11~~12/~~01~~27/2016 – ~~11~~01/~~11~~10/~~2016~~2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Generator Operators

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan
5. **Effective Date:** See the Implementation Plan for EOP-005-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for ~~system~~ System restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually- ~~-~~agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring ~~authority~~ operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator ~~at least once each 15 calendar months~~annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has ~~at least once each 15 calendar months~~annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes ~~is confusing~~has been seen as confusing to some Responsible Entities. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.

~~Therefore, the EOP SDT revisions now provide clarity. By revising this to read as "that would change the ability to implement its restoration planto reflect System modifications that would change the ability to implement its restoration plan," the intent iswas that the TOP update its restoration plan when major modifications need to be made that affect its ability to implement its restoration plan as describe in Requirement R1 Parts 4.1 and 4.2, not that the Transmission Operator has to make updates for minor revisions, such as element number changes or device changes that have no significance to the implementation of the plan.~~ The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

R4. Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement ~~of~~ its restoration plan ~~to reflect System modifications that would change the ability to implement its restoration plan~~, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. ~~No more than~~Within 90 calendar days after identifying ~~the Transmission Operator identifies~~ any unplanned permanent ~~System~~ BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006~~No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications~~.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response ~~for each step of the restoration~~. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 ~~would allow~~ allows operating personnel to gain experience on all stages of restoration~~and coordination needed through all of the stages of restoration~~, including coordination needed ~~in the transfer~~transferring ~~of~~ Demand and resource balance~~control~~ operations back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

R8. Each Transmission Operator shall include within its operations training program, annual System restoration training ~~at least once each 15 calendar months~~ for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority. ~~for Area Control Error and Automatic Generation Control.~~

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every ~~two calendar years~~24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as ~~e-mails with~~dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every ~~two~~ 24 calendar ~~years~~ months to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence~~, such as dated training records,~~ that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~Compliance Monitoring Period and Reset Time Frame~~Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in ~~force~~ effect since the last monitoring activity for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.

- The current restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity, as well as one previous monitoring activity period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in ~~force~~ effect since its last monitoring activity for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in ~~force~~ effect since its last monitoring activity on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last monitoring activity for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last monitoring activity records and all requested and submitted subsequent monitoring activity records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.3. Compliance Monitoring and Enforcement Processes**~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigations~~
- ~~Self-Reporting~~
- ~~Complaints~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.~~

~~1.4. Additional Compliance Information~~

~~None.~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three of the ~~r~~requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement ~~it~~the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. OR Transmission Operator failed to provide at least half of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~ ~~The Transmission Operator failed to update and submit~~	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~	The Transmission Operator has failed to update and submit its revised restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification~~change~~. OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	~~its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.~~	~~The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.~~	~~The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change~~.	The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator prior to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 24-calendar-month~~within a two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				from the Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	restoration plan within 24 hours but did make the notification within 48 hours.	restoration plan within 48 hours but did make the notification within 72 hours.	restoration plan within 72 hours but did make the notification within 96 hours.	restoration plan for more than 96 hours.
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a 24-calendar-	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a t24-calendar-	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		month~~two-calendar-year~~ period.	month~~wo-calendar-year~~ period.	
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/25/2016 – 12/08/2016
10-day final ballot	12/27/2016 – 01/10/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator; and

7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.

- The current, approved restoration plan and any restoration plans in effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program,	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~06/22/2016 – 08/08/2016~~
45-day formal comment period with additional ballot	~~08~~10/~~30~~25/2016 – ~~10~~12/~~14~~08/2016
10-day final ballot	~~11~~12/~~01~~27/2016 – ~~11~~01/~~11~~10/~~2016~~2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop~~, maintain,~~ and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with ~~adjacent~~ Transmission Operators in other Reliability Coordinator Areas, and with ~~adjacent~~ Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within ~~15~~ 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within ~~15~~ 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within ~~30 calendar days in accordance with Requirement R4~~the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, ~~at least once each 15 calendar months~~annual~~,~~ System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator; and

7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months~~two calendar years~~.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~Compliance Monitoring Period and Reset Time Frame~~ Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in ~~force~~ effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in ~~force~~ effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.

- The current, approved restoration plan and any restoration plans in ~~force~~ effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement ~~Processes~~ Program

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigations~~
- ~~Self-Reporting~~
- ~~Complaints~~

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.4. Additional Compliance Information:** None~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within ~~15~~ 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, ~~-~~from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, ~~-~~from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, ~~-~~from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training ~~at least once each 15 calendar~~	The Reliability Coordinator did not include the annual System restoration training ~~at least once each 15~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~months~~ within its operations training program, but did not address both of the requirement parts.	~~calendar months~~ within its operations training program.
R8.	N/A~~The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.~~	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon ~~BOT~~ Board adoption, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3 Requirement R1,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		EOP-005-2 Requirement R7, is redundant to EOP-005-3 Requirement R1.
EOP-005-2, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.	The EOP SDT revisions harmonize the use of "BES modification" and clarify the timing for unplanned permanent and planned permanent BES modifications.
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	every five years" to eliminate any ambiguity in the prior language.
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training	The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	annually for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority.	the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. Federal Energy Regulatory Commission (Commission) Order no. 749:

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every 24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	*"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		term “unique tasks.” The industry understands “unique tasks” to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify “unique tasks.”
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	The word “email” doesn’t capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every 24 calendar months to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and	“Two calendar years” was revised to “24 calendar months” for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
bus. The training program shall include training on the following:	energizing a bus. The training program shall include training on the following:	
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. . Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	**1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area with Transmission Operators in other Reliability Coordinator Areas and with Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4. .	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4 Part 4.1.	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" for clarity.
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3,

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk*	"To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	*Factor = Medium] [Time Horizon = Operations Planning]*	

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. ~~The EOP SDT removed the language: "*…to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System*" in Requirement R1, as it is covered in Requirement R1, Part 1.8.~~ Due to the addition of the word "implement," the phrase, "Real-time

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3~~,~~ Requirement R1, EOP-005-2~~,~~ Requirement R7, is redundant to EOP-005-3~~,~~ Requirement R1.
EOP-005-2, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator ~~at least once each 15 calendar months~~annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.		Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall update and submit its revised restoration plan to ~~to~~ its Reliability Coordinator for approval, ~~that~~when the revision would change ~~the~~its ability to implement its restoration plan, as follows~~Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. ~~This language creates two ambiguities. First, the phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes; however, no time frame is specified for~~

Standard: EOP-005-3		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
		~~updating the restoration plan for a planned BES modification. One could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications.~~ ~~Second, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Some "system modifications" can include "BES modifications". Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.~~ ~~For clarity, the EOP SDT revise the language in this Requirement to require a TOP to update its restoration plan to only reflect System modifications that affect its ability to implement its restoration plan as describe in Requirement R1 Parts. The intent is not to capture minor modifications that would have no impact on the implementation of a restoration, such as element number changes or device changes~~

Standard: EOP-005-3		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
		~~that have no significance to the implementation of the plan.~~ The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within ~~No more than~~ 90 calendar days after identifying ~~the Transmission Operator identifies~~ any unplanned permanent ~~System~~ BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements ~~in order to meet~~	The EOP SDT revisions harmonize the use of "BES modification" and clarify the timing for unplanned permanent and planned permanent BES modifications.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~the Reliability Coordinator approval requirement~~ per EOP-006~~No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications~~.	
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation*	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation*	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Risk Factor = Medium] [Time Horizon = Long-term Planning]	*Risk Factor = Medium] [Time Horizon = Long-term Planning]*	
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following:	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training ~~at least once each 15 calendar months~~annually for its System Operators. This training program shall include training on the	~~The language, "…at least once each 15 calendar months…" was added to provide clarity and to align training with the timing for updates to the restoration plan.~~ The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor = Medium] [Time Horizon = Operations Planning] **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority. ~~for Area Control Error and Automatic Generation Control.~~	Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every ~~two calendar years~~24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		periodic review templates and the SAR) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify "unique tasks."
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every 24 calendar months to each of its operating personnel responsible for the startup of its	"Two calendar years" was revised to "24 calendar months" for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Resource generation units and energizing a bus. The training program shall include training on the following:	Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, ~~maintain,~~ and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. . Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	*= Operations Planning, Real-time Operations]* **1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area~~,~~ with ~~adjacent~~ Transmission Operators in other Reliability Coordinator Areas~~,~~ and with ~~adjacent~~ Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4. .	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4 Part 4.1.	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" for clarity.
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop~~, maintain,~~ and implement" to

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop~~, maintain,~~ and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program~~, at least once each 15 calendar months~~ annual~~,~~ System restoration training for its System Operators. This training program shall	~~Language for timeframe was added for clarity.~~ "To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing "data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
~~EOP-008-1, Requirement R5~~ ~~**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~EOP-008-2, Requirement R5~~ ~~**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~
~~EOP-008-1, Requirement R7~~ ~~**R7.** Each Reliability Coordinator, Balancing~~	~~EOP-008-1, Requirement R7~~	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
~~Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~**R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	

Unofficial Comment Form

Project 2015-08 – Emergency Operations

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Operations; EOP-005-3 – System Restoration from Blackstart Resources** and **EOP-006-3 – System Restoration Coordination**. The electronic form must be submitted by **8 p.m. Eastern, Friday, December 9, 2016.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email), or at (404) 446-9671.

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT) that resulted from the PRT's review of a subset of EOP Standards. The Periodic Review comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous.

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 –Revise the standard; and
- EOP-008-1 – Revise the standard.

The four NERC Reliability Standards in the Periodic Review project concerned methodologies for restoring, reporting, and communicating Emergencies. Implementation of revisions and retirements recommended by the EOP PRT clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards, while making the standards more Results-based.

Questions

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

5. Please provide any additional comments for the EOP SDT to consider, if desired.

   Comments:

Consideration of Issues and Directives

Project 2015-08 Emergency Operations

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*	FERC Order Number 749	The Project 2015-02 Emergency Operations Periodic Review Team (EOP PRT), as well as the Project 2015-08 Emergency Operations Standards Drafting Team (EOP SDT) determined (through conducted outreach and comment questions/responses during postings of periodic review templates, the project SAR, and project postings) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the Transmission Operator (TOP), Transmission Owner (TO), and the Distribution Provider (DP). A rationale box was added to EOP-005-3, Rquirement R9 to clarify "unique tasks." **Rationale:** The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.
Clarify when system changes will trigger a requirement to update restoration plans. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for updating restoration	FERC-NERC-Regional Entity Joint Review of Restoration	The Project 2015-08 EOP SDT revised EOP-005-3, Requirement R4 and the requirement parts. The references to unplanned permanent and planned permanent BES modifications that will change the ability to implement the Reliability Coordinator (RC)-approved restoration plan are intended to require a TOP to

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
plans for all system modifications that would change the implementation of an entity's restoration plan for an extended period of time, not just permanent or planned system modifications. In considering these measures, the kinds of events that may warrant an update to the system restoration plan should be identified, taking into account the length of time the system is affected, as well as the overall objective of ensuring that restoration plans are generally flexible enough so that system modifications can be addressed without continuous updates.	and Recovery Plans. **Section IV.E**	update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RC's ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.
Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits.6 In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new	FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. **Section IV.G**	The EOP SDT discussed the recommendation to address the "…need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably…" The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan, these also have to be submitted to the RC for review, 3) include within its operations training program annual System restoration training

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
blackstart generator location or on redefinition of a cranking path).		for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC 1) has to review its restoration plan within 13 calendar months of the last review, 2) has to review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) has to review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed to system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System, and the RC is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, that both entities are continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation.
Operator training: Exercises on transferring control back to the balancing authority. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to	FERC-NERC-Regional Entity Joint Review of	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised in EOP-005-3, Requirement R1, Part 1.9 to the standard: "Processes for

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
address system restoration training and drilling for transitioning from transmission operator island control to balancing authority ACE/AGC7 control.	Restoration and Recovery Plans. **Section IV.H.**	transferring operations ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three of the ~~r~~requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement part” and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective” and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to update and submit its revised restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator prior to a planned permanent BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a 24-calendar-month period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a 24-calendar-month period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "their" with "its." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a 24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a 24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a 24-calendar-month period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a 24-calendar-month period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	High
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three of the ~~r~~requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.~~it.~~

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective” and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~ ~~The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.~~	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~ ~~The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.~~	The Transmission Operator updated and submitted its revised restoration plan to the Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification~~change~~. ~~OR~~ ~~The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change.~~	The Transmission Operator has failed to update and submit its revised restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification~~change~~. OR The Transmission Operator failed to update and submit its revised restoration plan to the Reliability Coordinator prior to a planned permanent BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a 24-calendar-month~~two-calendar-year~~ period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "their" with "its." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a 24-calendar-month~~two-calendar-year~~ period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “High” which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "implementation date" with "effective date." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the annual System restoration training within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "annual" with "at least once each 15 calendar months" and by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	High
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	Moderate	High	Severe
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “implementation date” with “effective date.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the annual System restoration training ~~at least once each 15 calendar months~~ within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the annual System restoration training ~~at least once each 15 calendar months~~ within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “annual” with “at least once each 15 calendar months” and by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
~~The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.~~	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement

Reminder

Project 2015-08 Emergency Operations
EOP-005-3 and EOP-006-3

Additional Ballots and Non-binding Polls Open through December 9, 2016

Now Available

Additional ballots for **EOP-005-3 - System Restoration from Blackstart Resources** and **EOP-006-3 - System Restoration Coordination** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, December 9, 2016**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and non-binding polls by clicking here. If you experience any difficulties in using the electronic form, contact Nasheema Santos.

Note: If a member cast a vote in the previous ballot, that vote will not carry over to this additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in this ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations
EOP-005-3 and EOP-006-3

Formal Comment Period Open through December 9, 2016

Now Available

A 45-day formal comment period for **EOP-005-3 - System Restoration from Blackstart Resource** and **EOP-006-3 - System Restoration Coordination** is open through **8 p.m. Eastern, Friday, December 9, 2016.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted November 30 – December 9, 2016.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Development, Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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NERC Balloting Tool (/) Dashboard (/) Users Ballots Comment Forms

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/69)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 AB 2 ST
Voting Start Date: 11/30/2016 12:01:00 AM
Voting End Date: 12/9/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 251
Total Ballot Pool: 310
Quorum: 80.97
Weighted Segment Value: 76.93

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	80	1	46	0.742	16	0.258	0	3	15
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	66	1	42	0.764	13	0.236	0	3	8
Segment: 4	18	1	7	0.7	3	0.3	0	1	7
Segment: 5	74	1	37	0.712	15	0.288	0	4	18
Segment: 6	51	1	30	0.714	12	0.286	0	1	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	310	6.8	178	5.231	61	1.569	0	12	59

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Negative	Comments Submitted
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Abstain	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		None	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Third-Party Comments
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Erick Barrios		None	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		None	N/A
5	Westar Energy	Laura Cox		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 310 of 310 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/69)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 AB 2 ST
Voting Start Date: 11/30/2016 12:01:00 AM
Voting End Date: 12/9/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 244
Total Ballot Pool: 295
Quorum: 82.71
Weighted Segment Value: 77.17

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	38	0.745	13	0.255	0	10	13
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	64	1	38	0.76	12	0.24	0	7	7
Segment: 4	17	0.8	5	0.5	3	0.3	0	3	6
Segment: 5	70	1	31	0.738	11	0.262	1	13	14
Segment: 6	49	1	24	0.75	8	0.25	0	9	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	295	6.6	152	5.093	49	1.507	1	42	51

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	James Anderson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Abstain	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		None	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Abstain	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Erick Barrios		None	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		None	N/A
5	Westar Energy	Laura Cox		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 295 of 295 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/69)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP AB 2 NB
Voting Start Date: 11/30/2016 12:01:00 AM
Voting End Date: 12/9/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 232
Total Ballot Pool: 289
Quorum: 80.28
Weighted Segment Value: 75.69

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	32	0.762	10	0.238	17	14
Segment: 2	7	0.3	3	0.3	0	0	4	0
Segment: 3	66	1	36	0.783	10	0.217	11	9
Segment: 4	16	0.9	6	0.6	3	0.3	1	6
Segment: 5	68	1	30	0.732	11	0.268	11	16
Segment: 6	46	1	23	0.742	8	0.258	6	9
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	1
Segment: 9	1	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	8	0.7	5	0.5	2	0.2	1	0
Totals:	289	6.1	137	4.618	44	1.482	51	57

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	James Anderson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Martine Blair		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		None	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Negative	Comments Submitted
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Abstain	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		None	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Erick Barrios		None	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Laura Cox		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 289 of 289 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/69)
Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP AB 2 NB
Voting Start Date: 11/30/2016 12:01:00 AM
Voting End Date: 12/9/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 226
Total Ballot Pool: 276
Quorum: 81.88
Weighted Segment Value: 75.64

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	29	0.806	7	0.194	21	12
Segment: 2	7	0.3	2	0.2	1	0.1	4	0
Segment: 3	64	1	33	0.786	9	0.214	14	8
Segment: 4	14	0.7	4	0.4	3	0.3	3	4
Segment: 5	64	1	25	0.714	10	0.286	15	14
Segment: 6	45	1	18	0.75	6	0.25	12	9
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	1
Segment: 9	1	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	8	0.7	5	0.5	2	0.2	1	0
Totals:	276	5.9	118	4.356	38	1.544	70	50

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	James Anderson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Abstain	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		None	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Abstain	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		None	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Laura Cox		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 276 of 276 entries

Previous 1 Next

Standards Announcement

Project 2015-08 Emergency Operations
EOP-005-3 and EOP-006-3

Formal Comment Period Open through December 9, 2016

Now Available

A 45-day formal comment period for **EOP-005-3 - System Restoration from Blackstart Resource** and **EOP-006-3 - System Restoration Coordination** is open through **8 p.m. Eastern, Friday, December 9, 2016.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted November 30 – December 9, 2016.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Development, Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-08 Emergency Operations | EOP-005-3 and EOP-006-3
Comment Period Start Date:	10/26/2016
Comment Period End Date:	12/9/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP AB 2 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP AB 2 NB

There were 53 sets of responses, including comments from approximately 44 different people from approximately 41 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

5. Please provide any additional comments for the EOP SDT to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Bill Watson	Old Dominion Electric Cooperative	3,4	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland	5	FRCC

						Electric		
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC

					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC

					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,5	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Shannon Weaver	Midcontinent Independent System Operator	2	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
Southwest	Shannon	2	SPP RE	SPP	Shannon Mickens	Southwest	2	SPP RE

Power Pool, Inc. (RTO)	Mickens			Standards Review Group		Power Pool Inc.		
					James Nail	Independence Power and Light	3	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Robert Gray	Board of Public Utilities (BPU) Kansas City, KS	3	SPP RE
					Lonnie Lindekguel	Southwest Power Pool	2	SPP RE
					Chris Dodds	Westar Energy	1,3,5,6	SPP RE

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The revisions as posted to R4 create redundant language. SRP recommends removal of the language requiring the TOP to “update” from R4. Additionally, It is also unclear how significant of a change “would change [the TOP’s] ability to implement its restoration plan”. This could work for many entities allowing administrative changes to the restoration plan without requiring RC approval. However, this language creates a potential for issues with R1, R2, and R5 which all reference an “approved restoration plan”.	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP supports the overall direction and efforts of this project team, and believe that the latest draft is an improvement to the previous version, we have chosen once again to vote negative on EOP -005-3. The text “upd to the RC where the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts” is only included in the callout, and is not in any way included within the obligation itself. In addition, what might be considered a substanitive change could be very subjective. As a result, there is a risk of inconsistent interpretation of the obligation by Responsible Entities and Auditors alike. At the very least, verbiage within the callout should be moved, at least in part, to the obligations themselves. In addition, it may be beneficial to also provide some clarity as to what a substantive change *is* to supplement the examples already provided for what it *is not*. For example, additional scenarios could be given related to changes that increase restoration time significantly or change the primary cranking path. These examples of what would and would-not be sustanitive changes could be provided in a Guidelines and Techical Basis section	
Likes 0	
Dislikes 0	

Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Bonneville Power Administration (BPA) suggests revising the cause for submission of a revised restoration plan to "submit its revised restoration plan to its Reliability Coordinator for approval when a BES change would impact its ability to implement its restoration plan..."	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Part 4.2 of the proposed standard is still unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that. The proposed wording on part 4.2 is not clear what the intent is. R4 requires a Transmission Operator to "update and submit" its revised restoration plan for approval subject to parts 4.1 and 4.2. The phrase "subject to the Reliability Coordinator approval requirements per EOP-006" doesn't make sense when the requirement and part 4.2 are read in total.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.	

The NSRF suggests changing R4 to read: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval.” Subrequirements, 4.1 and 4.2 can be deleted.

R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, “prior to implemnenting a planned permanent BES modification” is ambigiuous.

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 6

Answer	No
Document Name	

Comment

The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.

LES suggests modifing R4 as follows:

R4: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, revise and submit its restoration plan to its Reliability Coordinator for approval.”

R4.1 “Within 90 calendar days after identifying any unplanned permanent BES modifications.

R4.2 “At least 30 days prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.” (EOP-006 just states that the RC shall determine whether the TOP’s restoration plan is coordinated with and compatible with other TOPs’ restoration plans within its RC Area. At least 30 days prior to will allow the RC the 30 days it is allowed for approval before the planned modification is energized.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	

The rationale box expresses that Unplanned System Modifications could include Natural Disasters or major equipment failures.... and then suggests that outages are not unplanned system modifications; however most natural disasters and equipment failures results in outages. This does not clarify the intent of Unplanned System Modifications

Likes 0	
Dislikes 0	
Response	

larry brusseau - Corn Belt Power Cooperative - 1

Answer	No
Document Name	
Comment	

The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliability Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.

I suggests changing R4 to read: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval.” Subrequirements, 4.1 and 4.2 can be deleted.

R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, “prior to implementing a planned permanent BES modification” is ambiguous.

Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	No
Document Name	
Comment	

As written the language causes confusion regarding the TOP's ability to implement changes to its restoration; language implies that a revised plan would change the entitiy's ability to implement that revised plan. To remedy this it is suggested that the SDT consider making changes to the effect as follows:

R4. *Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its the currently approved RC restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. *Within 90 calendar days after identifying any unplanned permanent BES modifications.*

4.2. *Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.*

In addition, the implementation period for the revised restoration plan's approval creates a compliance time gap that could result with potentially different interpretations between auditors, entities, and the RC. During the timeframe of RC reviewing and approving an entity's revised restoration plan, it would be helpful to identify a defined period that allows implementation of an entity's revised plan that provides implementation of the "unapproved" plan to be valid through the end of the RC approval process.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

We believe the wording of the requirement could be improved to better reflect the apparent intent. The words "revised" and "revision" are used in different contexts in the same sentence which causes confusion. Also, system modifications may not be the only reason to update the plan. We suggest the wording be modified to something along the lines of:

R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows: 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA supports the suggestion of changing R4 to read: "Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator's ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval." Subrequirements, 4.1 and 4.2 can be deleted.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The EOP-005's purpose is to "[e]nsure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Similarly, EOP-006's purpose is to "[e]nsure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Simply put, the EOP Standards at issue in this project exist to ensure that personnel have clear, effective understanding of the System restoration process, that understanding is shared between TOPs and RCs through coordination and situational awareness, and priority is placed on such efforts. This is a critical reliability task. In light of this importance of these Standards to restoring grid operations, Texas RE continues to be concerned that the proposed changes to these Standards could result in confusion in implementing restoration plans, undermining their stated goals. Simply put, the proposed Standards, as currently drafted, presents a real risk that TOPs and RCs will not have single, clear restoration plans that both entities fully understand during the restoration process and will, therefore, not be able to effectively coordinate restoration efforts. This constitutes a significant reliability issue that the SDT must address in this process.	

Texas RE has identified two significant areas in the proposed EOP-005 Standard in particular that could result in confusion in the ultimate implementation of restoration plans.

First, as Texas RE noted previously, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification “that would change the ability to implement” the restoration plan (EOP-005-3, Requirement R4). Although, Texas RE does not necessarily object to the SDT’s stated intent to require formal updates requiring RC approval solely for material changes, the requirement to update a plan and obtain such an approval should not hinge upon the entity’s perception of its corresponding “ability” to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness.

In addition, Texas RE is concerned that Requirement R4 does not capture the fact that both planned and unplanned permanent BES modifications are subject to RC approval requirements per EOP-006. Texas RE recommends changing the R4 parent requirement to: "Each TOP shall update and submit its revised restoration to its Reliability Coordinator for approval in accordance with EOP-006.” This would indicate EOP-006 approval requirements apply to both 4.1 and 4.2.

If the SDT wishes to capture a materiality threshold for required updates and submissions, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update “to reflect system modifications that would materially change the implementation of its restoration plan.” Texas RE further recommends that the SDT include language requiring summaries of non-material revisions to the plan be at least provided to the RC through a streamlined information sharing process. As such, the SDT should also include language in R3 along the following lines: “Each Transmission Operator shall submit summaries of any immaterial revisions to its restoration plan to its Reliability Coordinator within 45 days of such immaterial changes. For such immaterial changes, no approval by the Reliability Coordinator shall be necessary.” Such language will facilitate effective communication between the TOP and the RC, which is critical to ultimately ensure personnel are prepared to enable System restoration and reliability is maintained throughout the process, while retaining a more streamlined approach for smaller changes.

Second, Texas RE remains concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar days of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval.

The purpose of EOP-005 is to have a clear, understood restoration process. While Texas RE appreciates the SDT’s efforts, the SDT should address areas in which the proposed Standard could result in overlapping, conflicting, or multiple versions of restoration plans.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We suggest changing the proposed R4 from:

R4 Each TOP shall update and submit its revised restoration plan to its RC for approval when the revision would change its ability to implement its restoration plan as follows:

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the RC approval requirements per EOP-006

First of all, the revision doesn't affect your ability to implement the Restoration Plan, it is the Plan. We think what the SDT really means here is you have experienced some change that impacts your ability to implement the approved Plan, and therefore you have to make a revision.

Second, as written, this only addresses a change that you would make due to a BES modification. What if the revision is due to a procedural/organizational change?

We think a better wording would be something like:

R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows:

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) We thank the SDT for attempting to develop a requirement that would apply to TOPs, but only after the identification of a substantive change that impacts the TOP's ability to implement its restoration plan or impact the RC's ability to monitor and direct restoration efforts.

(2) We find the proposed Requirement R4 is confusing regarding when a TOP is required to revise its system restoration plan, particularly since a revision appears to be tied solely to a BES modification. This could be a significant burden for entities to track. We believe the requirement should clarify upfront its application to a selective set of TOPs, and only under certain conditions identified by the SDT. We propose the following language

instead, “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall revise and submit its restoration plan to its Reliability Coordinator for approval.” (3) We have concerns with the SDT’s proposal for Part 4.2, particularly to a general reference to the EOP-006 System Restoration Coordination Standard, and not a specific revision to the standard. We feel this standard could easily become unbundled or change in the future. (4) Moreover, could the RC or other NERC functional entities have an opportunity to influence a planned permanent BES modification other than through the System Restoration Coordination Standard, such as with a retirement of a large generator or introduction of a RAS? (5) Furthermore, we ask the SDT to clarify the exact moment just “prior to implementing a planned permanent BES modification.” Is it just before the modification is permanently and electrically connected or disconnected from the System, or during its construction phase when the availability of other existing Facilities are affected? (6) Likewise, the SDT has assumed that a TOP will revise its restoration plan only under anticipated BES modifications. We believe other reasons could exist, such as for information or operational technology infrastructure modifications or organizational restructuring, which could impact its ability to implement its plan. Hence, we proposed the following language for Part 4.2 instead, “Within 90 calendar days of identifying a change that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts.”

Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM’s concern with Requirement R6 as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement: “R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify”	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	

AZPS agrees with requirement R4 and offers the following suggested wording for the proposed standard to enhance clarity:

Each Transmission Operator shall update and submit **its revised restoration plan** to its Reliability Coordinator for approval**, when it has identified planned or unplanned permanent BES modifications that meet the below criteria and would adversely impact its ability to implement** its current, approved restoration plan, as follows:

Likes 0	
Dislikes 0	
Response	

Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC

Answer	Yes
Document Name	
Comment	

Although the Rationale for Requirement R4 explains the qualification criteria for a BES modification, when the Rationale section is removed from the EOP-005-3 standard, Reclamation respectfully suggests a footnote be added to R4.4.1 to clarify a BES modification.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language “at least once each 15 calendar months” back to “annual” or “annually,” as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the ‘outer bounds’ of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the ‘agreed upon schedule’ with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an ‘annual’ review.

The proposed R5 of EOP-006-3 would read:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months.

The proposed R3 of EOP-005-3 would read:

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule.

Based on Operations Training programs, we support the change to “annual” in R8. There is no need to arbitrarily limit the length of time to 15 calendar months.

We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than ‘every two years’. We feel two calendar years provides more flexibility to match up training schedules and equipment availability. We are not simply looking for more time, just looking for flexibility to match schedules.

Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE supports retention of the 15 calendar month requirement and opposes the change back to “annual” or “annually.” Under the interpretation language cited by the SDT, this change would permit TOPs to delay the review and submit restoration plans for almost two calendar years. Again, EOP-005’s stated purpose is to “ensure plans, Facilities and personnel are prepared to enable System restoration.” Consistent with this principle, a clear 15-month requirement to review and submit restoration plans appears to advance the stated goal of ensuring preparedness to enable System restoration. At a minimum, Texas RE requests that the SDT provide a reliability-based reason for retaining the “annual” submission requirement as opposed to the previously proposed 15-month requirement.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

For Compliance concerns "Annual" is not a defined term. At least once every 15 months is clear.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the ‘outer bounds’ of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the ‘agreed upon schedule’ with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an ‘annual’ review.

The proposed R5 of EOP-006-3 would read:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months.

The proposed R3 of EOP-005-3 would read:

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule.

Based on Operations Training programs, we support the change to “annual” in R8. There is no need to arbitrarily limit the length of time to 15 calendar months.

We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than ‘every two years’. We feel two calendar years provides more flexibility to match up training schedules and equipment availability which is challenging, especially when personnel are dispersed over a wide multi-state area as it is in our case.

Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.

Likes 0	
Dislikes 0	

Response

larry brusseau - Corn Belt Power Cooperative - 1

Answer	No
Document Name	

Comment

If the language is changed to “annual”; “Annual” needs to be defined and included in the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC

Answer	No
Document Name	

Comment

Reclamation is aware that some EROs believe that the term “annual” may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the “annual” review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an “annual” activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity’s potential confusion and compliance violations. Therefore, Reclamation recommends the language “at least once ***every*** 15 calendar months” be retained.

Likes 0	

Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	

The standards are a minimum that must be met in order to be compliant. There is nothing in the standards saying an entity cannot do something, such as in this case a review, more often. The standard if left alone clearly states “at least once every 15 calendar months”, which can mean:

- the review can be completed on January 1, 2016 and then again on March 29, 2017;
- or it could mean once on January 1, 2016 and again on January 1, 2017;
- or on January 1, 2016 then again on February 1, 2016, then again on March 1, 2016, then etc. etc.

LES believes the entities that commented asking for the change back to “annual” are misunderstanding the intent of “at least once each 15 calendar months”. By changing the language to “annual” you are creating several issues:

- misinterpretation of the word “annual” as it is not a NERC Glossary Term
- reliance on a Compliance Application Notices (CANs) which are not industry approved or enforceable
- an unnecessary burden on entities as it tightens the timeline for reviews
- the term “annual” has been removed from multiple standards in favor of “at least once each 15 calendar months”

If the language is changed to “annual”; “Annual” needs to be defined and included in the NERC Glossary of Terms, however, this is in contradiction to other standards moving away from the term annual (i.e. CIP V5)

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

We appreciate the SDT’s efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of “annual” within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
IPC agrees with changing the language back to "Annual/Annually". However, the term Annual should be defined or point to where it is defined. Is annual 11–13 months? Or is it calendar year? If it is calendar year, there is some concern around what happens if an operator is trained each year, but the time between training is well over 12 months. For example, training occurs in March of 2017 and then the next training is December of 2018. This would be 21 months apart, but training was completed each year.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy strongly agrees with the change back to “annual” (per our comments to the previous revision), but questions the change in R9 and R15 from “every two calendar years” to “every 24 calendar months”. We feel this is the same issue previously raised with the “annual” language and question why the SDT, in the same revision where they went back on the previous change to “annual”, would at the same time change this language to apply in a way that is not consistent with the “annual” requirements. Xcel Energy recommends reverting to “every two calendar years”.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word "adjacent". The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	

Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	No
Document Name	
Comment	
In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word "adjacent". The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Comments: Part 1.2 should at least have the word "other" inserted befor the last use of Reliability Coordinators. In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement. In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the	

calendar year requirement.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
R 1.2 should have the word "other" inserted befor the last use of Reliability Coordinators. In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement. In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	
1. LES believes R3 should be changed to "at least once every 15 calendar months" to match EOP-005. The RC timeline and the TOP timeline should not be different. 2. LES agrees with R7, however 'annual' could be better stated as "at least once each calendar year". LES believes all training should be done on an annual (calendar year basis). 3. LES believes every two calendar years is much easier to track than 24 calendar months, since that makes it rolling.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	
Comment	
Duke Energy recommends that the drafting team consider changing the calendar month language used throughout the standard. We believe that use of the term “annual” or “annually” throughout the standard is necessary, and not just in R7.	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	No
Document Name	
Comment	
See Southern Company and GSOC comments.	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	No
Document Name	
Comment	
See GSOC and Southern Company comments.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

R 1.2 should have the word “other” inserted befor the last use of Reliability Coordinators.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

We disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration.

We also disagree with the removal of “adjacent” in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC’s should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word “adjacent” be included there as this provides the needed clarity.

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No

Document Name	
Comment	

We also continue to disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration.

We also disagree with the removal of “adjacent” in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC’s should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word “adjacent” be included there as this provides the needed clarity.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	

We believe the SDT should use its authority, as outlined within this project’s SAR, to review Requirement R7 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a RC’s systematic approach to training program, as required within various PER standards. At the very least, we ask the SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT appreciates the efforts to clarify the issue of interpretation on the words "neigbboring" and "adjacent." However, the term “’neighboring’ in no ways gives the RC the latitude to define which applicable entities are to be included in its restoration plan, since this term could be interpreted either way by entities and auditors allike until a NERC project or NERC SDT defines the meaning of "neighboring" or "adjacent" in reference to the ERCOT interconnection. ERCOT would prefer specificity on what this means, rather than leaving it unclear, given the duty to coordinate if we are "neighboring." ERCOT asks the SDT to clarify the meaning of the words "adjacent" or "neigboring" and provides this example:

1. Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring ***(i.e., within the same interconnection)*** Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include:..."

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1,	

5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned there is no requirement for the Reliability Coordinator to provide its restoration plan to Transmission Operators outside the Reliability Coordinator Area. There is also no requirement for a Transmission Operator to provide its restoration plan with a Reliability Coordinator that is not its own contained within EOP-005.) If there is criteria required to re-establish interconnections with other TOPs in other Reliability Coordinator Areas, it is prudent to provide the restoration plan to those TOPs. Simply providing the restoration plan to the neighboring RC does not mean the TOP (in the neighboring RC Area) will be aware as the neighboring RC is under no obligation to provide that specific plan to its TOPS.

Texas RE noticed there is a different time period between the Reliability Coordinator and the Transmission Operators to review their restoration plans. EOP-005-2 Requirement, R3 which requires Transmission Operators to review and submit its restoration plan annually while EOP-006-3, R3 requires the Reliability Coordinator to review its plan within 13 calendar months. Texas RE is concerned the two plans may not be coordinated if they are reviewed (and potentially revised) at different times.

In addition, Texas RE respectfully requests rationale as to why EOP-006-3 Requirement R3 changed the review to within 13 months from 15 months.

Likes 0	
Dislikes 0	

Response

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language “at least once each 15 calendar months” back to “annual” or “annually,” as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports retention of the 15 calendar month requirement and opposes the change back to “annual” or “annually.” Texas RE is concerned CAN-010 could allow for training on critical tasks to take place almost two years apart.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to “annual” or “annually”. If the language is changed to “annual”; “Annual” needs to be defined and included in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	

Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	No
Document Name	
Comment	
Reclamation is aware that some EROs believe that the term “annual” may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the “annual” review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an “annual” activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity’s potential confusion and compliance violations. Therefore, Reclamation recommends the language “at least once ***every*** 15 calendar months” be retained.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	
LES believes training should be required either every calendar year or every other calendar year, but disagrees with changing the wording to “annual” in R7 as it is too ambiguous. LES also disagrees with changing EOP-006 R3 (for reviewing restoration plan) from “within 15 calendar months” to “within 13 calendar months” too.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT’s efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of “annual” within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes	

could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Clarify definition of Annual. (See question 2 response.)	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the proposed change referenced in the question, but suggests the drafting team consider using the terms “annual” or “annually” in all pertinent areas throughout the standard.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to “annual” or “annually” as noted in comments above.	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Please provide any additional comments for the EOP SDT to consider, if desired.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
We would like the SDT to consider separating EOP-005-2 R1 into 2 requirements for a few reasons. The subparts of the requirement are not applicable to the implementation of the plan resulting in a awkwardly worded requirement. The assessment of the plan is critical to the reliability of the BES and the plan should linclude all of the identified parts, but it becomes obscure, secondary even in consideration with the implementation of the plan. Additionally, the EROs within NERC are working to develop an updated violation calculator for consideration when addressing potential violations. Per a recent WECC compliance workshop, the calculator is likely to include the consideration of “Time-Horizon”, which given that R1 has 2, creates confusion.	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Regarding EOP-005-3 R8.5 and R1.9: Bonneville Power Administration (BPA) suggests modifying the applicability of R1.9 and R8.5 to Transmission Operators operating solely as Transmission Operators and not concurrently operating as a Balancing Authority because a transfer does not take place for joint entities.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	
Document Name	
Comment	
Dominion suggests that “the TOP’s ability to implemenet the plan” be struck from the R4 Rationale. Dominion is of the opinion that sentence will be	

clearer without this information and that it more closely mirrors the intention of the Standards Drafting Team.

The sentence should now read: “The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts.”

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	
Document Name	

Comment

Based on the draft of RSAW, HQT suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:*

High] [*Time Horizon: Operations Planning, Long*]-*Term Planning*

☐ Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP’s applicability to the entity’s other Blackstart Ressource including other locations; or

☐ Explain in a declaration why corrective actions are beyond the entity's control owould not improve BES reliability, and that no further corrective actions will be taken.

☐Submit the conclusion(s) to the Transmission Operator

Typo from M15 to be corrected in coordination with R15 :

M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	
Document Name	

Comment

Although Portland General Electric Company (PGE) voted "affirmative" during this round of balloting, PGE feels strongly that ANY training requirements identified in the development of a standard should be addressed in the PER training standards and not in separate standards and requirements. The Systematic Approach to Training is as such that training requirements from other standards are easily adoptable into the training regimen. Adding requirements outside of the PER standards becomes an administrative nightmare by duplicating efforts relating to tracking and the application of the actual training.

Additionally, similar to the change made in Requirement R8, there is no reason to change Requirement R9 from two calendar years to 24 calendar months. Perhaps it seems like every two calendar years and every 24 calendar months are the same thing but it isn't. By changing the measurement to months, the tracking that is required starts in the month the training is given for any particular individual. Based on the individual schedules the tracking takes on a scattered approach, akin to herding cats. Please seriously consider changing R9 back to every two calendar years.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

We find EOP-005 -3 R1 redline changes to be confusing. The requiremnt needs additional clarification or should be restated. Does the requiremnt address real-time or study mode? Consider replacing the comma after "service" with a period and restating the second clause as a seperate sentence.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5

Answer	
Document Name	

Comment

In EOP-005 R9, recommend the following language: “Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every **two calendar years** to their field switching personnel identified as performing unique tasks associated with the Transmission Operator’s restoration plan that are outside of their normal tasks. **Unique tasks are those tasks that are defined by each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider.”**

In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In the first round of comments we provided the comment in regards to Section C1.1.2 Evidence Retention for replacing "last monitoring acitivity" to "last compliance audit".

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to “last monitoring activity” and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads “If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant”. For the underlined portion of this sentence ‘until found compliant’ we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone “compliant”. One suggestion is “..until the entity is notified that the remedy for non-compliance is complete”.

Likes 0	

Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

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Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

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Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF provides a negative opinion for the EOP-005-3 VSLs and offers the following comments:

1. VSL for R1 –
   i. RF notes the SDT had updated the Severe VSL for Requirement R1 but still believes there is a gap. For example, as modified it now states "…but failed to implement the applicable requirement parts within Requirement R1." Since all sub-parts under Requirement R1 are applicable, this new language is basically stating the entity failed to implement all nine sub-parts. Once again there is a gap when an entity fails to meet between four and eight sub-parts. RF suggest the following as an additional "OR" VSL to the Severe VSL to address our concern.
      a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.
2. VSL for R8 –
   i. In the consideration of comments report, the SDT responded: "The EOP SDT reviewed your comment and made conforming changes." When RF reviews the new redline version, there are no changes shown for the VSLs for R8. RF understands Requirement R8 had been modified and had replaced the "15 months" language with "annual", but this should still be reflected in the VSLs. RF recommends modifying the Severe VSL level as follows:
      a. Severe VSL - The Transmission Operator has not included [annual] System restoration training in its operations training program

RF provides a negative opinion for the EOP-006-3 VSLs and offers the following comments:

1. VSL for R5 –
   i. In the previous comment period, RF noted that since word "notification" is not in Requirement R5, there is subsequently no requirement for notifications. RF suggested removing the second "OR" VSL from each of the VSL Categories. In the consideration of comments the SDT responded: "The EOP SDT reviewed your comments, but agreed that 'notified' is in M5; and, therefore, did not make any changes." RF would like to remind the SDT that the NERC *Violation Severity Level Guidelines* document states: "A Violation Severity

	Level (VSL) is a post-violation measurement of the degree to which a Reliability Standard Requirement was violated (Lower, Moderate, High, or Severe)." As we can see, it references Requirements being violated and not Measures. If the SDT believes notification is an important piece, RF suggests including notifications to the language in Requirement R5. Absent including notification language in Requirement R5, RF continues to suggest removing the second "OR" VSL from each of the VSL Categories as "notifications" are not required by the Requirement.
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In the first round of comments we provided the following comment in regards to Section C1.1.2 Evidence Retention and we are also providing the drafting team response here:

In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	

Document Name	
Comment	

IPC does not agree with the new requirement 1.9 of requiring a process to transfer operations back to the Balancing Authority in accordance with RC criteria. Based on NERC definition of Balancing Authority, this function includes "maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." So, a Balancing Authority function is maintained at all times, even during a System Restoration, so there is no process "to transfer operation back to the BA." The Balancing Authority should be involved in the Restoration of the system from initiation of event to resumption of "Normal Operations." The NERC functional Model describes real-time actions of the Balancing Authority entity to "Implement System Restoration plans as directed by the Transmission Operator."

In R9, maintain calendar year language throughout whole standard.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	
Comment	

CenterPoint Energy appreciates the SDT's continued efforts to incorporate the industry's comments and concerns into the current drafts for EOP-005-3 System Restoration from Blackstart Resources and EOP-006-3 System Restoration Coordination.

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	
Comment	

AZPS agrees with requirement R1 and offers the following suggested wording for the proposed standard to enhance clarity:

Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System **to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage** following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service...

Likes 0	
Dislikes 0	

Response

Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC

Answer	
Document Name	

Comment

Reclamation recommends the following additional change to the existing Draft Standard EOP-005-3, R1, second sentence:

Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state wherein the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart resource is located within the Transmission Operator's System.

Reclamation recommends replacing "the Reliability Coordinator" with "its Reliability Coordinator" in the following locations: EOP-005-3, Requirements and measures R10, R16, M16, and VSL Table R4, VSL Table R10, and VSL Table R16 to be consistent throughout the Standard.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

In EOP-006-3, R1, the requirement states "The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**." On the other hand the restoration plan ends, "…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas." If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC restoration plan because all TOPs and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC restoration plan and then ending their RC restoration plan at the same time. The drafting team should clarify when the RC restoration plan should be implemented such that the Requirement does not conflict with itself.

In EOP-005-3, it is very clear the TOP restoration plan begins when a Blackstart Resource is required to restore a shut down area to service. This is different than when the RC restoration plan begins in EOP-006-3. There could be instances where the RC implements their restoration plan but no TOP within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with the start and end of the TOP restoration plans.

The RC restoration plan is developed for the RC but it contains criteria that the TOP will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOPs. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOP's restoration plan should be developed in coordination with its Reliability Coordinator's restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operator defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOP restoration plan when the TOP is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOP restoration plan shall include, “Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator’s restoration plan and*** are coordinated with the Reliability Coordinator’s high level strategy for restoring the interconnection.”

We recommend that where requirements are removed from the standard (such as in EOP-005-3), that the number for the deleted requirement remain and be notated as “Retired,” “Removed,” or “Intentionally left blank,” so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	
Document Name	

Comment

Thank you for your time and efforts!

Likes 0	
Dislikes 0	

Response

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1

Answer	
Document Name	

Comment

I wish to adopt the following PJM comments:

Comments: R6

PJM's concern with this requirement as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement:

"R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify"

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language.

We believe the following change to the proposed **R1.9** would provide better clarity as to the intent of the SDT. If the intent is different, we request additional clarity be provided in a response to our comment.

1.9. Operating Processes for transferring operational control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

Also in **R8** of the proposed **EOP-005-3**, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows:

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its training program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7 language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	
Document Name	

Comment

FMPA believes many of the requirements in these standards are administrative in nature and should be considered for retirement. We also believe the revisions being proposed will not improve stakeholder understanding of the requirements or reliability, and may even lead to further confusion. Furthermore, the redlines posted by the drafting team lead reviewers to believe changes are being proposed that are not in fact changes from the current approved versions. A redline comparison to the current approved version should be provided to allow voters to easily understand the revisions being proposed. FMPA suggests leaving the current approved versions in place.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE remains concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if “the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration.” As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs “resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator.” Although it is perhaps possible to read R1.1’s mandate that the restoration plan include “[s]trategies for system restoration that are coordinated with the [RC’s] high level strategy for restoring the interconnection” as encompassing this requirement, it is not clear that resynchronization is included within either “system restoration strategies” or the RC’s “high level strategy.” Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator..

Texas RE also notes that several substantive elements are also not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a Disturbance, but also that if “the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration.” As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate:

1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to “coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization.” Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC’s restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC’s existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement

R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following:

1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators

Texas RE identified several other areas for improvement:

- Texas RE requests the SDT provide a reason for removing the phrase "for each step of the restoration" from the rationale for EOP-005-3 Requirement R6.

- Texas RE disagrees with use of the term "unique tasks" in EOP-005-3 Requirement 9. That could cause confusion since it is undefined. Texas RE recommends using the term "restoration tasks" instead to indicate these are tasks are specific to restoration.

- Texas RE recommends the VSL for EOP-006-3 Requirement R8 include the piece about requesting the each Transmission Operator and Generator Operator identified in the restoration plan to participate in Reliability Coordinator drills per 8.1. While the VSLs address that the RC should conduct a drill, it does not reference who should participate.

- Texas RE respectfully requests the SDT provide a basis for its decision to adopt a 12-month implementation plan for both EOP-005-3 and EOP-006-3, including any data it considered in determining that this was an appropriate window for affected entities to meet their compliance obligations under the revised Standards.

-

As suggested before, Texas RE recommends there be a project to define and distinguish the terms "neighboring" and "adjacent". Texas RE noticed the mapping document states "The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary." Texas RE does believe further clarification is necessary as these terms appear throughout Standards and are undefined.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	

Comment

We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language.

We have discussed and believe the following change to the proposed R1.9 would provide some better clarity as to the intent of the SDT. If the intent is different, we request some additional clarity be provided in a response to our comment. Thank you.

1.9. Operating Processes for transferring operationsal control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

Also in R8 of the proposed EOP-005-3, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows:

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its traingin program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7 language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We thank the SDT for listening to our previously submitted comments, specifically the removal of "maintain" from requirement language and incorporation of "annual" within appropriate requirements.

(2) However, we question the language listed within Requirement R1 of EOP-005-1. We question if the SDT meant to remove "to service" from the

phrase "…required to restore the shutdown area to service," before adding the proposed language "to a state whereby the choice of the next Load to be restored is not driven…" We recommend removing the "to service" reference from the requirement to alleviate confusion.

(3) We caution the SDT on its capitalization of "Load" in Requirement R1 of EOP-005-1. According to the NERC Glossary of Terms, the definition refers to an "end-use device or customer that receives power from the electric system." While a TOP who is part of a vertically integrated utility may have the ability to choose which end-use customers it can restore and in what order, other utility business models rely on BAs and DPs to select pre-defined load block quantities as part of its restoration strategy. We recommend that the term "load" should not be capitalized in this context.

(4) We believe the SDT should use its authority, as outlined within this project's SAR, to review Requirement R8 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a TOP's systematic approach to training program, as required within various PER standards. At the very least, we ask the SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1.

(5) We believe the wording with Part 8.5 of EOP-005-3 needs to be clarified. The assumption is the TOP will transfer Demand and resource balance operations within its Transmission Operator Area over to the Balancing Authority. However, there could exist multiple BAs within the TOP's Area. Even the NERC Glossary definition for a BA identifies that a BA can only maintain Demand and resource balance within its own Balancing Authority Area. We believe the language should be clarified to read "Transition of Demand and resource balance to an affected Balancing Authority."

(6) We find the Section C.1.2 of the EOP-005-3 standard confusing with references to "last monitoring activity." We believe the SDT should revise the entire section and replicate the language listed in an already approved standard, like EOP-004-3. Within that specific standard, the Responsible Entity retains evidence of compliance since the last compliance audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

(7) We disagree with the SDT's assessment that the VSLs for R10 and R16 "meet or exceed the current level of compliance." We believe the VSLs for these requirements should be structured according to a percentage of the applicable personnel who need to be trained. This is a similar concept as used for defining the VSLs for R15.

(8) We thank the SDT for this opportunity to provide comments on these standards.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion

Answer	
Document Name	

Comment

Based on the draft of RSAW, we suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:*

High] [*Time Horizon: Operations Planning, Long*]-*Term Planning*

-Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP's applicability to the entity's other Blackstart Ressource including other locations; or

-Explain in a declaration why corrective actions are beyond the entity's control or

would not improve BES reliability, and that no further corrective actions will be

taken.

-Submit the conclusion(s) to the Transmission Operator

Typo from M15 to be corrected in coordination with R15.quirement :

M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Likes 0	
Dislikes 0	

Response

Tim Kucey - PSEG - PSEG Fossil LLC - 5

Answer	
Document Name	

Comment

adopt comments of PJM WRT EOP-005-3 R6

Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	
Document Name	
Comment	

In EOP-006-3 R1 the requirement states “The scope of the Reliability Coordinator’s restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**.” On the other hand the restoration plan ends, “…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas.” If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC Restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC Restoration Plan because all TOps and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC Restoration Plan and then ending their RC Restoration plan at the same time. The drafting team should clarify when the RC Restoration Plan should be implemented such that the Requirement does not conflict with itself.

In EOP-005-3, it is very clear the TOp restoration plan begins when a Blackstart Resource is required to restore the a shut down area to service. This is different than when the RC Restoration Plan begins in EOP-006-3. There could be instances where the RC implements their restoration plan but no TOp within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with the start and end of the TOp Restoration plans .

The RC restoration plan is developed for the RC but it contains criteria that the TOp will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOps. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOps restoration plan should be developed in coordination with its Reliability Coordinator restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operators defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOp restoration plan when the TOp is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOp restoration plan shall include, “Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator’s restoration plan and*** are coordinated with the Reliability Coordinator’s high level strategy for restoring the interconnection.”

We recommend that where requirements are removed from the standard, that the number for the deleted requirement remain and be notated as “Retired,” “Removed,” or “Intentionally left blank,” so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.

Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
We do not understand the justifications for the change made to R1 (“to a state whereby the choice of the next Load to be restored…”). We’d like to request for the Standard Drafting Team to provide Rationale on the purpose of the change and example of where the choice of next Load to be restored “would be” driven by the need to control the frequency or voltage. Alternatively, the SDT may modify the wording to clarify.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2
Comment Period Start Date:	10/26/2016
Comment Period End Date:	12/9/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP AB 2 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP AB 2 NB

There were 53 sets of responses, including comments from approximately 44 different people from approximately 41 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

5. Please provide any additional comments for the EOP SDT to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power	1,5	Texas RE

						Cooperative, Inc.		
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Bill Watson	Old Dominion Electric Cooperative	3,4	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC

					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC

					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,5	MRO

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Shannon Weaver	Midcontinent Independent System Operator	2	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE

				Review Group	James Nail	Independence Power and Light	3	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Robert Gray	Board of Public Utilities (BPU) Kansas City, KS	3	SPP RE
					Lonnie Lindekguel	Southwest Power Pool	2	SPP RE
					Chris Dodds	Westar Energy	1,3,5,6	SPP RE

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The revisions as posted to R4 create redundant language. SRP recommends removal of the language requiring the TOP to “update” from R4. Additionally, It is also unclear how significant of a change “would change [the TOP’s] ability to implement its restoration plan”. This could work for many entities allowing administrative changes to the restoration plan without requiring RC approval. However, this language creates a potential for issues with R1, R2, and R5 which all reference an “approved restoration plan”.	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT agrees with your comment regarding redundant language and revised Requirement R4 as follows: Requirement R4 “Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:” The rationale for Requirement R4 addresses changes that would substantively change the TOP’s ability to implement its restoration plan: “The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.” Administrative changes would not substantively change the TOP’s ability to implement its restoration plan.	
Thomas Foltz - AEP - 5	

Answer	No
Document Name	
Comment	

While AEP supports the overall direction and efforts of this project team, and believe that the latest draft is an improvement to the previous version, we have chosen once again to vote negative on EOP-005-3. The text “update and submit a restoration plan to the RC when the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts” is only included in the callout, and is not in any way included within the obligation itself. In addition, what might be considered a substanitive change could be very subjective. As a result, there is a risk of inconsistent interpretation of the obligation by Responsible Entities and Auditors alike.

At the very least, verbiage within the callout should be moved, at least in part, to the obligations themselves. In addition, it may be beneficial to also provide some clarity as to what a substantive change *is* to supplement the examples already provided for what it *is not*. For example, additional scenarios could be given related to changes that increase restoration time significantly or change the primary cranking path. These examples of what would and would-not be sustanitive changes could be provided in a Guidelines and Techical Basis section

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Requirement 4, Parts 4.1 and 4.2 reference BES modifications. BES is defined in the NERC Glossary of Terms. The EOP SDT‘s intent is discussed in the Rationale Box for Requirement R4, which is retained with the standard in the Rationale Section upon FERC approval, that has the additional language: “Examples of instances that do not require update and submission of a restoration plan include element number changes, ~~or~~ device changes, or administrative changes that have no significance to the implementation of the plan.”

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Bonneville Power Administration (BPA) suggests revising the cause for submission of a revised restoration plan to "submit its revised restoration plan to its Reliability Coordinator for approval when a BES change would impact its ability to implement its restoration plan..."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement 4, Parts 4.1 and 4.2 reference BES modifications. BES is defined in the NERC Glossary of Terms. The EOP SDT's intent is discussed in the Rationale Box for Requirement R4, which is retained with the standard in the Rationale Section upon FERC approval, that has the additional language: "Examples of instances that do not require update and submission of a restoration plan include element number changes, ~~or~~ device changes, or administrative changes that have no significance to the implementation of the plan." The EOP SDT will retain the term "BES modification" in Requirement R4, Parts 4.1 and 4.2.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Part 4.2 of the proposed standard is still unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that. The proposed wording on part 4.2 is not clear what the intent is. R4 requires a Transmission Operator to "update and submit" its revised restoration plan for approval subject to parts 4.1 and 4.2. The phrase "subject to the Reliability Coordinator approval requirements per EOP-006" doesn't make sense when the requirement and part 4.2 are read in total.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The EOP SDT revised Requirement R4 as follows: “Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:” If the RC approval time period changes in EOP-006 then the timeframe in EOP-005 will also change. Referencing EOP-006 ensures EOP-005 remains consistent with any changes to EOP-006.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that. The NSRF suggests changing R4 to read: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval.” Subrequirements, 4.1 and 4.2 can be deleted. R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, “prior to implemnenting a planned permanent BES modification” is ambiguious.	
Likes 0	
Dislikes 0	
Response	
If the RC approval time period changes in EOP-006 then the timeframe in EOP-005 will also change. Referencing EOP-006 ensures EOP-005 remains consistent with any changes to EOP-006.	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No

Document Name	
Comment	

The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.

LES suggests modifing R4 as follows:

R4: "Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator's ability to monitor and direct restoration efforts, shall, revise and submit its restoration plan to its Reliability Coordinator for approval."

R4.1 "Within 90 calendar days after identifying any unplanned permanent BES modifications.

R4.2 "At least 30 days prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006." (EOP-006 just states that the RC shall determine whether the TOP's restoration plan is coordinated with and compatible with other TOPs' restoration plans within its RC Area. At least 30 days prior to will allow the RC the 30 days it is allowed for approval before the planned modification is energized.

Likes 0	
Dislikes 0	
Response	

If the RC approval time period changes in EOP-006 then the timeframe in EOP-005 will also change. Referencing EOP-006 ensures EOP-005 remains consistent with any changes to EOP-006.

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

The rationale box expresses that Unplanned System Modifications could include Natural Disasters or major equipment failures.... and then suggests that outages are not unplanned system modifications; however most natural disasters and equipment failures results in outages. This does not clarify the intent of Unplanned System Modifications	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the Rationale Box to remove both "The changes made in Requirement R4 and the requirement parts do not refer to outages," and "Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan." to the updated language refers to permanent BES modifications.	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliability Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that. I suggests changing R4 to read: "Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator's ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval." Subrequirements, 4.1 and 4.2 can be deleted. R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, "prior to implementing a planned permanent BES modification" is ambiguous.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The EOP SDT agrees with your comment regarding redundant language and revised Requirement R4 as follows: Requirement R4 "Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:" If the RC approval time period changes in EOP-006 then the timeframe in EOP-005 will also change. Referencing EOP-006 ensures EOP-005 remains consistent with any changes to EOP-006.	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	No
Document Name	
Comment	
As written the language causes confusion regarding the TOP's ability to implement changes to its restoration; language implies that a revised plan would change the entitiy's ability to implement that revised plan. To remedy this it is suggested that the SDT consider making changes to the effect as follows: ***R4.*** *Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its the currently approved RC restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* ***4.1***. *Within 90 calendar days after identifying any unplanned permanent BES modifications.* ***4.2.*** *Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.* In addition, the implementation period for the revised restoration plan's approval creates a compliance time gap that could result with potentially different interpretations between auditors, entities, and the RC. During the timeframe of RC reviewing and approving an entity's	

revised restoration plan, it would be helpful to identify a defined period that allows implementation of an entity's revised plan that provides implementation of the "unapproved" plan to be valid through the end of the RC approval process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT has revised Requirement R4 to read: "Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:" The EOP SDT discussed your comment regarding revisions to Requirement R4, but concluded the requirement is clear as written. Based on your implementation period question, EOP-005, Requirement R1, Part 1.1 requires strategies for System restoration. If your revised plan is currently in the approval process, you would refer to your strategies in your approved plan. For either permanent unplanned or permanent planned BES modifications, the RC still needs to approve the plan.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
We believe the wording of the requirement could be improved to better reflect the apparent intent. The words "revised" and "revision" are used in different contexts in the same sentence which causes confusion. Also, system modifications may not be the only reason to update the plan. We suggest the wording be modified to something along the lines of: R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows: 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The EOP SDT agrees with your comment regarding redundant language and revised Requirement R4 as follows: Requirement R4 "Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:"	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA supports the suggestion of changing R4 to read: "Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator's ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval." Subrequirements, 4.1 and 4.2 can be deleted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT agrees with your comment regarding redundant language and revised Requirement R4 as follows: Requirement R4 "Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:" Requirement 4, Parts 4.1 and 4.2 reference BES modifications. BES is defined in the NERC Glossary of Terms. The Requirements also discuss permanent unplanned and permanent planned BES modifications and the reporting timeframes.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

The EOP-005's purpose is to "[e]nsure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Similarly, EOP-006's purpose is to "[e]nsure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Simply put, the EOP Standards at issue in this project exist to ensure that personnel have clear, effective understanding of the System restoration process, that understanding is shared between TOPs and RCs through coordination and situational awareness, and priority is placed on such efforts. This is a critical reliability task.

In light of this importance of these Standards to restoring grid operations, Texas RE continues to be concerned that the proposed changes to these Standards could result in confusion in implementing restoration plans, undermining their stated goals. Simply put, the proposed Standards, as currently drafted, presents a real risk that TOPs and RCs will not have single, clear restoration plans that both entities fully understand during the restoration process and will, therefore, not be able to effectively coordinate restoration efforts. This constitutes a significant reliability issue that the SDT must address in this process.

Texas RE has identified two significant areas in the proposed EOP-005 Standard in particular that could result in confusion in the ultimate implementation of restoration plans.

First, as Texas RE noted previously, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification "that would change the ability to implement" the restoration plan (EOP-005-3, Requirement R4). Although, Texas RE does not necessarily object to the SDT's stated intent to require formal updates requiring RC approval solely for material changes, the requirement to update a plan and obtain such an approval should not hinge upon the entity's perception of its corresponding "ability" to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness.

In addition, Texas RE is concerned that Requirement R4 does not capture the fact that both planned and unplanned permanent BES modifications are subject to RC approval requirements per EOP-006. Texas RE recommends changing the R4 parent requirement to: "Each TOP shall update and submit its revised restoration to its Reliability Coordinator for approval in accordance with EOP-006." This would indicate EOP-006 approval requirements apply to both 4.1 and 4.2.

If the SDT wishes to capture a materiality threshold for required updates and submissions, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update "to reflect system modifications that would materially change the implementation of its restoration plan." Texas RE further recommends that the SDT include language requiring summaries of non-material revisions to the plan be at least provided to the RC through a streamlined information sharing process. As such, the SDT should also include language in R3 along the following lines: "Each Transmission Operator shall submit summaries of any immaterial revisions to its restoration plan to its Reliability Coordinator within 45 days of such immaterial changes. For such immaterial changes, no approval by the Reliability Coordinator shall be necessary." Such language will facilitate effective communication between the TOP and the RC, which is critical to ultimately ensure personnel are prepared to enable System restoration and reliability is maintained throughout the process, while retaining a more streamlined approach for smaller changes.

Second, Texas RE remains concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar days of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval.

The purpose of EOP-005 is to have a clear, understood restoration process. While Texas RE appreciates the SDT's efforts, the SDT should address areas in which the proposed Standard could result in overlapping, conflicting, or multiple versions of restoration plans.

Likes 0	
Dislikes 0	

Response

The EOP SDT reviewed your first comment and does not agree that all changes should be submitted to the RC; only changes that affect the ability to implement your plan should be submitted.

Requirement R4, Part 4.1 is still subject to the 30-day RC approval per EOP-006. The EOP SDT concluded the requirement is clear as written. Requirement R4 states that the TOP shall submit its revised restoration plan to its RC for approval when the revision would change its ability to implement its restoration plan.

Requirement 4, Parts 4.1 and 4.2 reference BES modifications. BES is defined in the NERC Glossary of Terms. The Requirements also discuss permanent unplanned and permanent planned BES modifications and the reporting timeframes. The EOP SDT discussed your comment regarding providing the RC a "streamlined" information process for immaterial changes, and does not agree that this should be a requirement. The RC has 30 days to approve or disapprove a TOP restoration plan after submittal per EOP-006, Requirement R5, for permanent planned or unplanned BES modifications. EOP-005, Requirement R1, Part 1.1 requires strategies for System restoration. If your revised plan is currently in the approval process, you would refer to your strategies in your approved plan.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We suggest changing the proposed R4 from: R4 Each TOP shall update and submit its revised restoration plan to its RC for approval when the revision would change its ability to implement its restoration plan as follows: 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification subject to the RC approval requirements per EOP-006 First of all, the revision doesn't affect your ability to implement the Restoration Plan, it is the Plan. We think what the SDT really means here is you have experienced some change that impacts your ability to implement the approved Plan, and therefore you have to make a revision. Second, as written, this only addresses a change that you would make due to a BES modification. What if the revision is due to a procedural/organizational change? We think a better wording would be something like:	

R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows: 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement 4, Parts 4.1 and 4.2 reference BES modifications. BES is defined in the NERC Glossary of Terms. The EOP SDT's intent is discussed in the Rationale Box for Requirement R4, which is retained with the standard in the Rationale Section upon FERC approval. The EOP SDT also added language to the Rationale Box: "Examples of instances that do not require update and submission of a restoration plan include element number changes, ~~or~~ device changes, or administrative changes that have no significance to the implementation of the plan." If the procedural/organizational revision changes the ability to implement the restoration plan, the restoration plan would need to be submitted to the RC for approval.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We thank the SDT for attempting to develop a requirement that would apply to TOPs, but only after the identification of a substantive change that impacts the TOP's ability to implement its restoration plan or impact the RC's ability to monitor and direct restoration efforts. (2) We find the proposed Requirement R4 is confusing regarding when a TOP is required to revise its system restoration plan, particularly since a revision appears to be tied solely to a BES modification. This could be a significant burden for entities to track. We believe the requirement should clarify upfront its application to a selective set of TOPs, and only under certain conditions identified by the SDT. We propose the following language instead, "Each Transmission Operator, who identifies a change in its restoration plan that would affect its	

ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall revise and submit its restoration plan to its Reliability Coordinator for approval.” (3) We have concerns with the SDT’s proposal for Part 4.2, particularly to a general reference to the EOP-006 System Restoration Coordination Standard, and not a specific revision to the standard. We feel this standard could easily become unbundled or change in the future. (4) Moreover, could the RC or other NERC functional entities have an opportunity to influence a planned permanent BES modification other than through the System Restoration Coordination Standard, such as with a retirement of a large generator or introduction of a RAS? (5) Furthermore, we ask the SDT to clarify the exact moment just “prior to implementing a planned permanent BES modification.” Is it just before the modification is permanently and electrically connected or disconnected from the System, or during its construction phase when the availability of other existing Facilities are affected? (6) Likewise, the SDT has assumed that a TOP will revise its restoration plan only under anticipated BES modifications. We believe other reasons could exist, such as for information or operational technology infrastructure modifications or organizational restructuring, which could impact its ability to implement its plan. Hence, we proposed the following language for Part 4.2 instead, “Within 90 calendar days of identifying a change that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. If the revision changes the ability to implement the restoration plan, the restoration plan would need to be submitted to the RC for approval. If the RC approval time period changes in EOP-006 then the timeframe in EOP-005 will also change. Referencing EOP-006 ensures EOP-005 remains consistent if EOP-006 changes. There are NERC standards that require coordination of BES modifications for the TOP and RC.	

In reference to your question on RCs or other NERC functional entities having an opportunity to influence a planned permanent BES modification other than through the System Restoration Coordination Standard. This standard focuses on "restoring the Interconnection" and the TOP having a restoration plan, it's up to the TOP to revise their restoration plan, when a planned permanent or unplanned permanent BES modification is made that would change their ability to implement their plan. In reference to your comment regarding implementing a planned permanent BES modification, it is up to the TOP to identify when there is a change that impacts their ability to implement the restoration plan and when the change needs to take effect. If a revision changes the ability to implement the restoration plan, the restoration plan would need to be submitted to the RC for approval.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM's concern with Requirement R6 as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement: "R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify"	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Thank you for your comment. The EOP SDT revised Requirement R6 to: "Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify:"	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with requirement R4 and offers the following suggested wording for the proposed standard to enhance clarity: Each Transmission Operator shall update and submit **its revised restoration plan** to its Reliability Coordinator for approval**, when it has identified planned or unplanned permanent BES modifications that meet the below criteria and would adversely impact its ability to implement** its current, approved restoration plan, as follows:	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT revised Requirement R4 as follows: "Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows:"	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Although the Rationale for Requirement R4 explains the qualification criteria for a BES modification, when the Rationale section is removed from the EOP-005-3 standard, Reclamation respectfully suggests a footnote be added to R4.4.1 to clarify a BES modification.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT's intent is discussed in the Rationale Box for Requirement R4, which is retained with the standard in the Rationale Section upon FERC approval.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language “at least once each 15 calendar months” back to “annual” or “annually,” as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the ‘outer bounds’ of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the ‘agreed upon schedule’ with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an ‘annual’ review.

The proposed R5 of EOP-006-3 would read:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months.

The proposed R3 of EOP-005-3 would read:

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule.

Based on Operations Training programs, we support the change to “annual” in R8. There is no need to arbitrarily limit the length of time to 15 calendar months.

We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than 'every two years'. We feel two calendar years provides more flexibility to match up training schedules and equipment availability. We are not simply looking for more time, just looking for flexibility to match schedules. Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. EOP-006, Requirement R3, requires the RC to review its plan every 13 calendar months. EOP-006, Requirement R5, requires the RC to review the TOP's plans within 30 days of receipt. EOP-005, Requirement R3, requires the TOP to review and submit its plan to the RC on an annual basis. Therefore, since these are individual requirements there is no gap or need for any revisions to these requirements. The EOP SDT agrees with your suggestion for Requirements R9 and R15 to change 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports retention of the 15 calendar month requirement and opposes the change back to "annual" or "annually." Under the interpretation language cited by the SDT, this change would permit TOPs to delay the review and submit restoration plans for almost two calendar years. Again, EOP-005's stated purpose is to "ensure plans, Facilities and personnel are prepared to enable System restoration." Consistent with this principle, a clear 15-month requirement to review and submit restoration plans appears to advance the stated goal of ensuring preparedness to enable System restoration. At a minimum, Texas RE requests that the SDT provide a reliability-based reason for retaining the "annual" submission requirement as opposed to the previously proposed 15-month requirement.	
Likes 0	

Dislikes 0	
Response	
The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. The EOP SDT discussed your comment on TOPs waiting two calendar years to review and submit the plan but disagree, given there is a mutually-agreed, predetermined review schedule.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
For Compliance concerns "Annual" is not a defined term. At least once every 15 months is clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	

Comment	
We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the 'outer bounds' of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the 'agreed upon schedule' with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an 'annual' review. The proposed R5 of EOP-006-3 would read: **R5.** Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months. The proposed R3 of EOP-005-3 would read: **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule. Based on Operations Training programs, we support the change to "annual" in R8. There is no need to arbitrarily limit the length of time to 15 calendar months. We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than 'every two years'. We feel two calendar years provides more flexibility to match up training schedules and equipment availability which is challenging, especially when personnel are dispersed over a wide multi-state area as it is in our case. Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. EOP-006, Requirement R3, requires the RC to review its plan every 13 calendar months. EOP-006, Requirement R5, requires the RC to review the TOP's plans within 30 days of receipt. EOP-005, Requirement R3, requires the TOP to review and submit its plan to the RC on an annual basis. Therefore, since these are individual requirements there is no gap or need for any revisions to these requirements. The EOP SDT agrees with your suggestion for Requirement R9 and Requirement R15, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
If the language is changed to "annual"; "Annual" needs to be defined and included in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	No
Document Name	
Comment	

Reclamation is aware that some EROs believe that the term “annual” may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the “annual” review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an “annual” activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity’s potential confusion and compliance violations. Therefore, Reclamation recommends the language “at least once ***every*** 15 calendar months” be retained.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. The EOP SDT discussed your comment on TOPs waiting two calendar years to review and submit the plan but disagree, given there is a mutually-agreed, predetermined review schedule.

Eric Ruskamp - Lincoln Electric System - 6

Answer	No
Document Name	

Comment

The standards are a minimum that must be met in order to be compliant. There is nothing in the standards saying an entity cannot do something, such as in this case a review, more often. The standard if left alone clearly states “at least once every 15 calendar months”, which can mean:

- the review can be completed on January 1, 2016 and then again on March 29, 2017;
- or it could mean once on January 1, 2016 and again on January 1, 2017;

- or on January 1, 2016 then again on February 1, 2016, then again on March 1, 2016, then etc. etc.

LES believes the entities that commented asking for the change back to “annual” are misunderstanding the intent of “at least once each 15 calendar months”. By changing the language to “annual” you are creating several issues:

- misinterpretation of the word “annual” as it is not a NERC Glossary Term
- reliance on a Compliance Application Notices (CANs) which are not industry approved or enforceable
- an unnecessary burden on entities as it tightens the timeline for reviews
- the term “annual” has been removed from multiple standards in favor of “at least once each 15 calendar months”

If the language is changed to “annual”; “Annual” needs to be defined and included in the NERC Glossary of Terms, however, this is in contradiction to other standards moving away from the term annual (i.e. CIP V5)

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

We appreciate the SDT's efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of "annual" within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
IPC agrees with changing the language back to "Annual/Annually". However, the term Annual should be defined or point to where it is defined. Is annual 11–13 months? Or is it calendar year? If it is calendar year, there is some concern around what happens if an operator is trained each year, but the time between training is well over 12 months. For example, training occurs in March of 2017 and then the next training is December of 2018. This would be 21 months apart, but training was completed each year.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy strongly agrees with the change back to "annual" (per our comments to the previous revision), but questions the change in R9 and R15 from "every two calendar years" to "every 24 calendar months". We feel this is the same issue previously raised with the "annual" language and question why the SDT, in the same revision where they went back on the previous change to "annual", would at the same time change this language to apply in a way that is not consistent with the "annual" requirements. Xcel Energy recommends reverting to "every two calendar years".	
Likes 0	
Dislikes 0	
Response	
The EOP SDT agrees with your suggestion for Requirements R9 and R15 to change 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of	

Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word “adjacent”. The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The EOP SDT has added the following rationale box: “The Purpose statement of EOP-006-3 states: “Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.”	

Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	No
Document Name	
Comment	

In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word “adjacent”. The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The EOP SDT has added the following rationale box: “The Purpose statement of EOP-006-3 states: “Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.”	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Comments: Part 1.2 should at least have the word “other” inserted befor the last use of Reliability Coordinators. In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement. In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT agrees with adding the word “other” before the last use of Reliability Coordinators in Requirement 1, Requirement part 1.2. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. The 13-month-review provides flexibility for restoration plans; to closely align with TOP’s restoration plan and the “annual” review language in the requirements. The EOP SDT agrees with your suggestion for Requirement R8, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with “annual” language in the requirements.

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
R 1.2 should have the word “other” inserted befor the last use of Reliability Coordinators. In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement. In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT agrees with adding the word "other" before the last use of Reliability Coordinators in Requirement 1, Requirement part 1.2. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". The 13-month-review provides flexibility for restoration plans; to closely align with TOP's restoration plan and the "annual" review language in the requirements. The EOP SDT agrees with your suggestion for Requirement R8, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.

Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	
1. LES believes R3 should be changed to "at least once every 15 calendar months" to match EOP-005. The RC timeline and the TOP timeline should not be different. 2. LES agrees with R7, however 'annual' could be better stated as "at least once each calendar year". LES believes all training should be done on an annual (calendar year basis). 3. LES believes every two calendar years is much easier to track than 24 calendar months, since that makes it rolling.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees with adding the word "other" before the last use of Reliability Coordinators in Requirement 1, Requirement part 1.2.	

The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". The 13-month-review provides flexibility for restoration plans; to closely align with TOP's restoration plan and the "annual" review language in the requirements. The EOP SDT agrees with your suggestion for Requirement R8, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends that the drafting team consider changing the calendar month language used throughout the standard. We believe that use of the term "annual" or "annually" throughout the standard is necessary, and not just in R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". With the revision back to "annual" in both EOP-005 and EOP-006, EOP-006, Requirement R3 was also revised back to the 13 months, as stated in the currently-enforced standard. The 13-month-review provides flexibility for restoration plans and closely aligns with TOP's restoration plan and the "annual" review language in the requirements.	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	

Answer	No
Document Name	
Comment	
See Southern Company and GSOC comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to Southern Company and GSOC comments.	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	No
Document Name	
Comment	
See GSOC and Southern Company comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to Southern Company and GSOC comments.	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	

Comment	
R 1.2 should have the word “other” inserted befor the last use of Reliability Coordinators.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with adding the word “other” before the last use of Reliability Coordinators in Requirement 1, Requirement part 1.2.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
We disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration. We also disagree with the removal of “adjacent” in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC’s should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word “adjacent” be included there as this provides the needed clarity.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The EOP SDT agrees with the Independent Experts Review Panel (IERP) to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1. The EOP SDT determined that the addition of "adjacent" in R1.2 is unnecessary and is captured by the use of "neighboring" in Requirement R1. "Neighboring" gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The Purpose statement of EOP-006-3 states: "Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection."	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". With the revision back to "annual" in both EOP-005 and EOP-006, EOP-006, Requirement R3 was also revised back to the 13 months, as stated in the currently-enforced standard. The 13-month-review provides flexibility for restoration plans; to closely align with TOP's restoration plan and the "annual" review language in the requirements.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We also continue to disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration.

We also disagree with the removal of “adjacent” in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC’s should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word “adjacent” be included there as this provides the needed clarity.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
The EOP SDT agrees with the Independent Experts Review Panel (IERP) to retire EOP-006-2, Requirement R8 as “a logical action that does not require a standard.” The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion).
In addition, by adding the language: “develop and implement” to EOP-006-3, requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.

The EOP SDT determined that the addition of “adjacent” in R1.2 is unnecessary and is captured by the use of “neighboring” in Requirement R1. “Neighboring” gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The Purpose statement of EOP-006-3 states: “Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.”

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe the SDT should use its authority, as outlined within this project's SAR, to review Requirement R7 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a RC's systematic approach to training program, as required within various PER standards. At the very least, we ask the SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT held extensive discussions on Requirement R7. Requirement R7 is being retained in EOP-006, as it is specific training with high impact, low occurrence. The PER-005 standard pertains to training processes.	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT appreciates the efforts to clarify the issue of interpretation on the words "neigbboring" and "adjacent." However, the term "'neighboring' in no ways gives the RC the latitude to define which applicable entities are to be included in its restoration plan, since this term could be interpreted either way by entities and auditors allike until a NERC project or NERC SDT defines the meaning of "neighboring" or "adjacent" in reference to the ERCOT interconnection. ERCOT would prefer specificity on what this means, rather than leaving it unclear,	

given the duty to coordinate if we are "neighboring." ERCOT asks the SDT to clarify the meaning of the words "adjacent" or "neigboring" and provides this example: 1. Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring ***(i.e., within the same interconnection)*** Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include:..."	
Likes 0	
Dislikes 0	
Response	
The EOP SDT determined that the addition of "adjacent" in R1.2 is unnecessary and is captured by the use of "neighboring" in Requirement R1. "Neighboring" gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The Purpose statement of EOP-006-3 states: "Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." The interties between Interconnections are in place for emergency situations; not sharing emergency plans would appear to be in direct conflict with the purpose of interties between Interconnections and could lead to exacerbated events.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned there is no requirement for the Reliability Coordinator to provide its restoration plan to Transmission Operators outside the Reliability Coordinator Area. There is also no requirement for a Transmission Operator to provide its restoration plan with a Reliability Coordinator that is not its own contained within EOP-005.) If there is criteria required to re-establish interconnections with other TOPs in other Reliability Coordinator Areas, it is prudent to provide the restoration plan to those TOPs. Simply providing the restoration plan to the neighboring RC does not mean the TOP (in the neighboring RC Area) will be aware as the neighboring RC is under no obligation to provide that specific plan to its TOPS.

Texas RE noticed there is a different time period between the Reliability Coordinator and the Transmission Operators to review their restoration plans. EOP-005-2 Requirement, R3 which requires Transmission Operators to review and submit its restoration plan annually while EOP-006-3, R3 requires the Reliability Coordinator to review its plan within 13 calendar months. Texas RE is concerned the two plans may not be coordinated if they are reviewed (and potentially revised) at different times.

In addition, Texas RE respectfully requests rationale as to why EOP-006-3 Requirement R3 changed the review to within 13 months from 15 months.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

The RCs in Requirement R2 are distributing their restoration plan to neighboring RCs and in Requirement R4 the RC is reviewing the neighboring RC plans and looking for conflicts. During restoration, it is up to the RCs to decide any restoration coordination that is needed from TOPs within their areas. There is nothing that precludes the RC or TOP from sending their plan to other entities.

The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. With the revision back to “annual” in both EOP-005 and EOP-006, EOP-006, Requirement R3 was also revised back to the 13 months, as stated in the currently-enforced standard. The 13-month-review provides flexibility for restoration plans and closely aligns with TOP’s restoration plan and the “annual” review language in the requirements.

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports retention of the 15 calendar month requirement and opposes the change back to "annual" or "annually." Texas RE is concerned CAN-010 could allow for training on critical tasks to take place almost two years apart.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. EOP-006, Requirement R3, was revised back to the 13 months.	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to “annual” or “annually”. If the language is changed to “annual”; “Annual” needs to be defined and included in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”.	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	No

Document Name	
Comment	
Reclamation is aware that some EROs believe that the term “annual” may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the “annual” review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an “annual” activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity’s potential confusion and compliance violations. Therefore, Reclamation recommends the language “at least once ***every*** 15 calendar months” be retained.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain “annual” in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining “annual”. EOP-006, Requirement R3, requires the RC to review its plan every 13 calendar months. EOP-006, Requirement R5, requires the RC to review the TOP’s plans within 30 days of receipt. EOP-005, Requirement R3, requires the TOP to review and submit its plan to the RC on an annual basis. Therefore, since these are individual requirements there is no gap or need for any revisions to these requirements. EOP-006, Requirement R3, was revised back to the 13 months.	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	

LES believes training should be required either every calendar year or every other calendar year, but disagrees with changing the wording to "annual" in R7 as it is too ambiguous. LES also disagrees with changing EOP-006 R3 (for reviewing restoration plan) from "within 15 calendar months" to "within 13 calendar months" too.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual". EOP-006, Requirement R3, was revised back to the 13 months, as stated in the currently-enforced EOP-006-2.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT's efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of "annual" within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Clarify definition of Annual. (See question 2 response.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT decided to maintain "annual" in EOP-005 and EOP-006 based on industry comments through postings and multiple outreach sessions. Many comments received from industry stated that their annual schedules are already in place based on how entities define annually. The *NERC CAN-0010 - Implementation of Annual in Reliability Standards Requirements* also provides guidance on defining "annual".	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the proposed change referenced in the question, but suggests the drafting team consider using the terms "annual" or "annually" in all pertinent areas throughout the standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support. The EOP SDT has updated the standard to align with the "annual/annually" language.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to "annual" or "annually" as noted in comments above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT has updated the standard to align with the "annual/annually" language.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Please provide any additional comments for the EOP SDT to consider, if desired.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
We would like the SDT to consider separating EOP-005-2 R1 into 2 requirements for a few reasons. The subparts of the requirement are not applicable to the implementation of the plan resulting in a awkwardly worded requirement. The assessment of the plan is critical to the reliability of the BES and the plan should linclude all of the identified parts, but it becomes obscure, secondary even in consideration with the implementation of the plan. Additionally, the EROs within NERC are working to develop an updated violation calculator for consideration when addressing potential violations. Per a recent WECC compliance workshop, the calculator is likely to include the consideration of “Time-Horizon”, which given that R1 has 2, creates confusion.	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
The intent of the EOP SDT in adding the language “develop and implement” is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The EOP SDT believes the RSAW covers the separation of “develop and implement” with the use of the following language: “Verify that the restoration plan was implemented (such as during Disturbances).” “Verify each Transmission Operator has a dated, documented System restoration plan developed in accordance with R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.”	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	

Document Name	
Comment	
Regarding EOP-005-3 R8.5 and R1.9: Bonneville Power Administration (BPA) suggests modifying the applicability of R1.9 and R8.5 to Transmission Operators operating solely as Transmission Operators and not concurrently operating as a Balancing Authority because a transfer does not take place for joint entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT discussed this situation and concluded that the TOP needs to address this in their restoration plan when they are also a BA.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	
Document Name	
Comment	
Dominion suggests that "the TOP's ability to implemenet the plan" be struck from the R4 Rationale. Dominion is of the opinion that sentence will be clearer without this information and that it more closely mirrors the intention of the Standards Drafting Team. The sentence should now read: "The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The EOP SDT has updated the rationale box to include your suggested revision.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

Based on the draft of RSAW, HQT suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:*

High] [*Time Horizon: Operations Planning, Long-Term Planning*]

 Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP’s applicability to the entity’s other Blackstart Ressource including other locations; or

Explain in a declaration why corrective actions are beyond the entity's control owould not improve BES reliability, and that no further corrective actions will be taken. Submit the conclusion(s) to the Transmission Operator Typo from M15 to be corrected in coordination with R15 : M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT does not agree a requirement needs to be added to the standard. If a Blackstart Resource fails a test, it is up to the TOP to resolve. The EOP SDT has updated Measure M15 as follows: "Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15."	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	
Document Name	
Comment	

Although Portland General Electric Company (PGE) voted "affirmative" during this round of balloting, PGE feels strongly that ANY training requirements identified in the development of a standard should be addressed in the PER training standards and not in separate standards and requirements. The Systematic Approach to Training is as such that training requirements from other standards are easily adoptable into the training regimen. Adding requirements outside of the PER standards becomes an administrative nightmare by duplicating efforts relating to tracking and the application of the actual training.

Additionally, similar to the change made in Requirement R8, there is no reason to change Requirement R9 from two calendar years to 24 calendar months. Perhaps it seems like every two calendar years and every 24 calendar months are the same thing but it isn't. By changing the measurement to months, the tracking that is required starts in the month the training is given for any particular individual. Based on the individual schedules the tracking takes on a scattered approach, akin to herding cats. Please seriously consider changing R9 back to every two calendar years.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The EOP SDT held extensive discussions on Requirement R10. Requirement R10 is being retained in EOP-005, as it is specific training with high impact, low occurrence. The PER-005 standard pertains to training processes.

The EOP SDT agrees with your suggestion for Requirement R9, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with “annual” language in the requirements.

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

We find EOP-005 -3 R1 redline changes to be confusing. The requiremnt needs additional clarification or should be restated. Does the requiremnt address real-time or study mode? Consider replacing the comma after "service" with a period and restating the second clause as a seperate sentence.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and now states: ”Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System. The restoration plan shall include:”	

Don Schmit - Nebraska Public Power District - 5	
Answer	
Document Name	
Comment	
In EOP-005 R9, recommend the following language: “Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every **two calendar years** to their field switching personnel identified as performing unique tasks associated with the Transmission Operator’s restoration plan that are outside of their normal tasks. **Unique tasks are those tasks that are defined by each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider.”** In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.	

In the first round of comments we provided the comment in regards to Section C1.1.2 Evidence Retention for replacing "last monitoring acitivity" to "last compliance audit". In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles? Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is. Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".	
Likes 0	
Dislikes 0	
Response	
The EOP SDT agrees with your suggestion for Requirement R9 and Requirement R15, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements. The rationale box will be retained with the standard in the Rationale Section, and the EOP SDT finds that the rationale box is the appropriate placement of the language for unique tasks. The EOP SDT agrees with your suggestion for Requirement R9 and Requirement R15, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with "annual" language in the requirements.	

The Evidence Retention Section has been updated to state "last compliance audit." Section C.1 has been revised to: "… is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer."	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	
Document Name	
Comment	
In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles? Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is. Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".	
Likes 0	
Dislikes 0	
Response	

The Evidence Retention Section has been updated to state "last compliance audit." Section C.1 has been revised to: "… is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer."

Jamison Cawley - Nebraska Public Power District - 1	
Answer	
Document Name	
Comment	

In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".

Likes 0	
Dislikes 0	
Response	

The Evidence Retention Section has been updated to state "last compliance audit." Section C.1 has been revised to: "… is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer."	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

RF provides a negative opinion for the EOP-005-3 VSLs and offers the following comments:

1. VSL for R1 –

   i. RF notes the SDT had updated the Severe VSL for Requirement R1 but still believes there is a gap. For example, as modified it now states "…but failed to implement the applicable requirement parts within Requirement R1." Since all sub-parts under Requirement R1 are applicable, this new language is basically stating the entity failed to implement all nine sub-parts. Once again there is a gap when an entity fails to meet between four and eight sub-parts. RF suggest the following as an additional "OR" VSL to the Severe VSL to address our concern.

      a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.

2. VSL for R8 –

   i. In the consideration of comments report, the SDT responded: "The EOP SDT reviewed your comment and made conforming changes." When RF reviews the new redline version, there are no changes shown for the VSLs for R8. RF understands Requirement R8 had been modified and had replaced the "15 months" language with "annual", but this should still be reflected in the VSLs. RF recommends modifying the Severe VSL level as follows:

a. Severe VSL - The Transmission Operator has not included [annual] System restoration training in its operations training program

RF provides a negative opinion for the EOP-006-3 VSLs and offers the following comments:

1. VSL for R5 –

   i. In the previous comment period, RF noted that since word “notification” is not in Requirement R5, there is subsequently no requirement for notifications. RF suggested removing the second “OR” VSL from each of the VSL Categories. In the consideration of comments the SDT responded: “The EOP SDT reviewed your comments, but agreed that ‘notified’ is in M5; and, therefore, did not make any changes.” RF would like to remind the SDT that the NERC *Violation Severity Level Guidelines* document states: "A Violation Severity Level (VSL) is a post-violation measurement of the degree to which a Reliability Standard Requirement was violated (Lower, Moderate, High, or Severe)." As we can see, it references Requirements being violated and not Measures. If the SDT believes notification is an important piece, RF suggests including notifications to the language in Requirement R5. Absent including notification language in Requirement R5, RF continues to suggest removing the second “OR” VSL from each of the VSL Categories as “notifications” are not required by the Requirement.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The EOP SDT updated the high VSL for Requirement R1 to read:
“The Transmission Operator has an approved plan but failed to comply with three or more of the ~~r~~equirement parts within Requirement R1.”
The EOP SDT discussed your comment regarding adding “annual” to severe VSL for Requirement R8. Requirement R8 addresses annual training, you are measured on whether system operations training is included in your operations training program.

To align Requirement R5, Part 5.1, the EOP SDT has updated the language of Requirement R5, Part 5.1 to state:

“5.1. The Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval,

with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator."	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In the first round of comments we provided the following comment in regards to Section C1.1.2 Evidence Retention and we are also providing the drafting team response here:

In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".

Likes 0	

Dislikes 0	
Response	
The EOP SDT agrees with your suggestion for Requirement R9 and Requirement R15, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with “annual” language in the requirements. The Evidence Retention Section has been updated to state “last compliance audit.” Section C.1 has been revised to: “… is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.”	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
IPC does not agree with the new requirement 1.9 of requiring a process to transfer operations back to the Balancing Authority in accordance with RC criteria. Based on NERC definition of Balancing Authority, this function includes "maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." So, a Balancing Authority function is maintained at all times, even during a System Restoration, so there is no process "to transfer operation back to the BA." The Balancing Authority should be involved in the Restoration of the system from initiation of event to resumption of "Normal Operations." The NERC functional Model describes real-time actions of the Balancing Authority entity to "Implement System Restoration plans as directed by the Transmission Operator." In R9, maintain calendar year language throughout whole standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The Balancing Authority does not relinquish any BA authority to the TOP. In draft 2 of EOP-005 the EOP SDT revised Requirement R1, Part 1.9 to read: “Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator’s criteria.” The EOP SDT agrees with your suggestion for Requirement R9, changing 24 calendar months back to two calendar years. It provides flexibility for training schedules and equipment availability. In addition, it better aligns with “annual” language in the requirements.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy appreciates the SDT’s continued efforts to incorporate the industry’s comments and concerns into the current drafts for EOP-005-3 System Restoration from Blackstart Resources and EOP-006-3 System Restoration Coordination.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
AZPS agrees with requirement R1 and offers the following suggested wording for the proposed standard to enhance clarity:	

Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System **to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage** following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service...

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and states: "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include:"

Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	
Document Name	

Comment
Reclamation recommends the following additional change to the existing Draft Standard EOP-005-3, R1, second sentence: Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state wherein the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart resource is located within the Transmission Operator's System.

Reclamation recommends replacing "the Reliability Coordinator" with "its Reliability Coordinator" in the following locations: EOP-005-3, Requirements and measures R10, R16, M16, and VSL Table R4, VSL Table R10, and VSL Table R16 to be consistent throughout the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and states: "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include:" "The Reliability Coordinator" has been updated to "its Reliability Coordinator" throughout the standard.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
In EOP-006-3, R1, the requirement states "The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**." On the other hand the restoration plan ends, "…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas." If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC restoration plan because all TOPs and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC restoration plan and then ending their RC	

restoration plan at the same time. The drafting team should clarify when the RC restoration plan should be implemented such that the Requirement does not conflict with itself. In EOP-005-3, it is very clear the TOP restoration plan begins when a Blackstart Resource is required to restore a shut down area to service. This is different than when the RC restoration plan begins in EOP-006-3. There could be instances where the RC implements their restoration plan but no TOP within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with the start and end of the TOP restoration plans. The RC restoration plan is developed for the RC but it contains criteria that the TOP will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOPs. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOP's restoration plan should be developed in coordination with its Reliability Coordinator's restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operator defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOP restoration plan when the TOP is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOP restoration plan shall include, "Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator's restoration plan and*** are coordinated with the Reliability Coordinator's high level strategy for restoring the interconnection." We recommend that where requirements are removed from the standard (such as in EOP-005-3), that the number for the deleted requirement remain and be notated as "Retired," "Removed," or "Intentionally left blank," so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. If an island was created internal to a TOP, then this is a localized TOP outage. If the outage rises to the level that you require the RC assistance, then you would need to communicate with the RC at that point. The EOP SDT discussed your concerns, but EOP-005 Requirement 1.1 covers strategies in which the TOP should coordinate with the RC and states: "Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the	

Interconnection." We agree with your comment that in EOP-006 Requirement R1 the scope of the restoration plan starts and ends in this situation, but the TOP still needs to restore the System.

Retired requirements are not retained in subsequent versions of a standard.

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	
Document Name	

Comment

Thank you for your time and efforts!

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1

Answer	
Document Name	

Comment

I wish to adopt the following PJM comments:

Comments: R6

PJM's concern with this requirement as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement:

"R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify"

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The EOP SDT revised Requirement R6 to state: "Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify:"

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language.

We believe the following change to the proposed **R1.9** would provide better clarity as to the intent of the SDT. If the intent is different, we request additional clarity be provided in a response to our comment.

1.9. Operating Processes for transferring operational control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

Also in **R8** of the proposed **EOP-005-3**, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows:

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its training program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7

language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. In response to industry comments, the EOP SDT revised the language in Requirement R1, Part 1.9, in draft 2 of EOP-005. The Balancing Authority does not relinquish any BA authority to the TOP. The revised language for Part 1.9 is as follows: "Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria." The EOP SDT made no substantive changes to Requirement R6 from EOP-005-2. Steady state and dynamic simulations were discussed and the drafting team does not believe that this team should expand detailed explanations. The EOP SDT created a rationale box for Requirement R6 that reads: "Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added." The EOP SDT did not elect to change the wording contained in Requirement 8, Part 8.1 and believes all GOPs and TOPs should be included, as identified in the TOP's restoration plan. The EOP SDT has updated the standard to align with the "annual/annually" language. EOP-006, Requirement R3, was revised back to the 13 months, as stated in the currently-enforced EOP-006-2. The EOP SDT finds Requirement R7 is clear as written and Measure M7 requires the training records for evidence.	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	
Document Name	

Comment	
FMPA believes many of the requirements in these standards are administrative in nature and should be considered for retirement. We also believe the revisions being proposed will not improve stakeholder understanding of the requirements or reliability, and may even lead to further confusion. Furthermore, the redlines posted by the drafting team lead reviewers to believe changes are being proposed that are not in fact changes from the current approved versions. A redline comparison to the current approved version should be provided to allow voters to easily understand the revisions being proposed. FMPA suggests leaving the current approved versions in place.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The purpose statement of EOP-005 states: "Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." The purpose statement of EOP-006 states: "Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." The EOP SDT concluded both standards are needed for reliability. A redline comparison to the currently-enforced standards will be posted when the standards are posted for final ballot. Draft 1 of the standards provided a redline to the currently-enforced standards; Draft 2 provided redlines to the last-posted drafts of the standards.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE remains concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.	

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration." As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs "resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator." Although it is perhaps possible to read R1.1's mandate that the restoration plan include "[s]trategies for system restoration that are coordinated with the [RC's] high level strategy for restoring the interconnection" as encompassing this requirement, it is not clear that resynchronization is included within either "system restoration strategies" or the RC's "high level strategy." Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator..

Texas RE also notes that several substantive elements are also not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration." As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate:

1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to "coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization." Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC's restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC's existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following:

1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators

Texas RE identified several other areas for improvement:

- Texas RE requests the SDT provide a reason for removing the phrase "for each step of the restoration" from the rationale for EOP-005-3 Requirement R6.
- Texas RE disagrees with use of the term "unique tasks" in EOP-005-3 Requirement 9. That could cause confusion since it is undefined. Texas RE recommends using the term "restoration tasks" instead to indicate these are tasks are specific to restoration.
- Texas RE recommends the VSL for EOP-006-3 Requirement R8 include the piece about requesting the each Transmission Operator and Generator Operator identified in the restoration plan to participate in Reliability Coordinator drills per 8.1. While the VSLs address that the RC should conduct a drill, it does not reference who should participate.
- Texas RE respectfully requests the SDT provide a basis for its decision to adopt a 12-month implementation plan for both EOP-005-3 and EOP-006-3, including any data it considered in determining that this was an appropriate window for affected entities to meet their compliance obligations under the revised Standards.
- As suggested before, Texas RE recommends there be a project to define and distinguish the terms "neighboring" and "adjacent". Texas RE noticed the mapping document states "The term "neighboring" should be interpreted as "adjacent" and no

further clarification is necessary." Texas RE does believe further clarification is necessary as these terms appear throughout Standards and are undefined.

Likes 0	
Dislikes 0	

Response

The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant. EOP-005-3 Requirement R1 states: "Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System." Requirement R1, Part 1.3 states: "Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator." The EOP SDT agrees that this language addresses the issue of the Requirement R7 retirement based upon your comment "…to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed."

The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant. Requirement R1, Parts 1.1, 1.3 and 1.7 covers re-establishing connections.

The rationale for EOP-005-3, Requirement R6 (draft 2) was previously written that dynamic simulations were needed for every step, which was not the intent of the current EOP SDT.

The EOP SDT agreed that the best way to address the intent of unique tasks was to draft the following rationale: "The intent of the term "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider."

The EOP SDT's intent for EOP-006-3, Requirement R8 requires the RC to conduct two drills per calendar year. The EOP SDT added a moderate VSL to capture Requirement R8, Part 8.1.

The Implementation Plan takes into account any barriers to implementation. The EOP SDT intent for the twelve-month Implementation Plan was to give all entities an appropriate time frame for implementation. The EOP SDT determined that the addition of "adjacent" in R1.2 is unnecessary and is captured by the use of "neighboring" in Requirement R1. "Neighboring" gives the RC the latitude to define which applicable entities are to be included in its restoration plan. The Purpose statement of EOP-006-3 states: "Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection."	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language. We have discussed and believe the following change to the proposed R1.9 would provide some better clarity as to the intent of the SDT. If the intent is different, we request some additional clarity be provided in a response to our comment. Thank you. **1.9.** Operating Processes for transferring operationsal control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria. Also in R8 of the proposed EOP-005-3, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows: **Rationale for Requirement R8:** The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.	

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its traingin program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7 language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. In response to industry comments, the EOP SDT revised the language in Requirement R1, Part 1.9, in draft 2 of EOP-005. The Balancing Authority does not relinquish any BA authority to the TOP. The proposed language of Part 1.9 is as follows: "Operating Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

The EOP SDT made no substantive changes to Requirement R6 from EOP-005-2, Requirement R6. Steady state and dynamic simulations were discussed and the drafting team does not believe that this team should expand detailed explanations. The EOP SDT created a rationale box for

Requirement R6 that reads: "Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added." The EOP SDT has updated the standard to align with the "annual/annually" language. EOP-006, Requirement R3, was revised back to the 13 months, as stated in the currently-enforced EOP-006-2. The EOP SDT finds Requirement R7 is clear as written and Measure M7 requires the training records for evidence.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) We thank the SDT for listening to our previously submitted comments, specifically the removal of "maintain" from requirement language and incorporation of "annual" within appropriate requirements. (2) However, we question the language listed within Requirement R1 of EOP-005-1. We question if the SDT meant to remove "to service" from the phrase "…required to restore the shutdown area to service," before adding the proposed language "to a state whereby the choice of the next Load to be restored is not driven…" We recommend removing the "to service" reference from the requirement to alleviate confusion. (3) We caution the SDT on its capitalization of "Load" in Requirement R1 of EOP-005-1. According to the NERC Glossary of Terms, the definition refers to an "end-use device or customer that receives power from the electric system." While a TOP who is part of a vertically integrated utility may have the ability to choose which end-use customers it can restore and in what order, other utility business models rely on BAs and DPs to select pre-defined load block quantities as part of its restoration strategy. We recommend that the term "load" should not be capitalized in this context. (4) We believe the SDT should use its authority, as outlined within this project's SAR, to review Requirement R8 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a TOP's systematic approach to training program, as required within various PER standards. At the very least, we ask the	

SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1. (5) We believe the wording with Part 8.5 of EOP-005-3 needs to be clarified. The assumption is the TOP will transfer Demand and resource balance operations within its Transmission Operator Area over to the Balancing Authority. However, there could exist multiple BAs within the TOP's Area. Even the NERC Glossary definition for a BA identifies that a BA can only maintain Demand and resource balance within its own Balancing Authority Area. We believe the language should be clarified to read "Transition of Demand and resource balance to an affected Balancing Authority." (6) We find the Section C.1.2 of the EOP-005-3 standard confusing with references to "last monitoring activity." We believe the SDT should revise the entire section and replicate the language listed in an already approved standard, like EOP-004-3. Within that specific standard, the Responsible Entity retains evidence of compliance since the last compliance audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. (7) We disagree with the SDT's assessment that the VSLs for R10 and R16 "meet or exceed the current level of compliance." We believe the VSLs for these requirements should be structured according to a percentage of the applicable personnel who need to be trained. This is a similar concept as used for defining the VSLs for R15. (8) We thank the SDT for this opportunity to provide comments on these standards.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and states: "Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include:"

The EOP SDT has not changed the lowercase word "load."

The EOP SDT held extensive discussions on Requirement R7. Requirement R7 is being retained in EOP-006, as it is specific training with high impact, low occurrence. The PER-005 standard pertains to training processes.

The EOP SDT discussed this situation and that the TOP needs to address this in their restoration plan when they are also a BA.

The Evidence Retention Section has been updated to state "last compliance audit."

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	
Document Name	
Comment	

Based on the draft of RSAW, we suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:* *High*] [*Time Horizon: Operations Planning, Long-Term Planning*] -Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP's applicability to the entity's other Blackstart Ressource including other locations; or -Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. -Submit the conclusion(s) to the Transmission Operator Typo from M15 to be corrected in coordination with R15.quirement : M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Likes 0	
Dislikes 0	

Response
The EOP SDT has updated Measure M15 to state: "Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a BUS and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15."

Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	

Document Name	
Comment	
adopt comments of PJM WRT EOP-005-3 R6	
Likes 0	
Dislikes 0	
Response	
Please see responses to PJM comments.	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	
Document Name	
Comment	

In EOP-006-3 R1 the requirement states "The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**." On the other hand the restoration plan ends, "…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas." If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC Restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC Restoration Plan because all TOps and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC Restoration Plan and then ending their RC Restoration plan at the same time. The drafting team should clarify when the RC Restoration Plan should be implemented such that the Requirement does not conflict with itself.

In EOP-005-3, it is very clear the TOp restoration plan begins when a Blackstart Resource is required to restore the a shut down area to service. This is different than when the RC Restoration Plan begins in EOP-006-3. There could be instances where the RC implements their

restoration plan but no TOp within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with the start and end of the TOp Restoration plans . The RC restoration plan is developed for the RC but it contains criteria that the TOp will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOps. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOps restoration plan should be developed in coordination with its Reliability Coordinator restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operators defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOp restoration plan when the TOp is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOp restoration plan shall include, “Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator’s restoration plan and*** are coordinated with the Reliability Coordinator’s high level strategy for restoring the interconnection.” We recommend that where requirements are removed from the standard, that the number for the deleted requirement remain and be notated as “Retired,” “Removed,” or “Intentionally left blank,” so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and states: ”Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System. The restoration plan shall include:” If an island was created internal to a TOP, then this is a localized TOP outage. And if it rises to the level that you require the RC assistance, then you would need to communicate with the RC at that point.	

EOP-005 Requirement 1.1 covers strategies in which the TOP should coordinate with the RC and states: “Strategies for System restoration that are coordinated with its Reliability Coordinator’s high level strategy for restoring the Interconnection.” We agree with your comment, in EOP-006 Requirement R1 that the scope of the restoration plan starts and ends in this situation, but the TOP still needs to restore the System. Retired requirements are not retained in subsequent versions of a standard.

Mike Smith - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
We do not understand the justifications for the change made to R1 (“to a state whereby the choice of the next Load to be restored…”). We’d like to request for the Standard Drafting Team to provide Rationale on the purpose of the change and example of where the choice of next Load to be restored “would be” driven by the need to control the frequency or voltage. Alternatively, the SDT may modify the wording to clarify.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT revised Requirement R1 for clarity. Requirement R1 refers to Real-time and Operations Planning horizons and states: ”Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System. The restoration plan shall include:”	

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/06/2016

Anticipated Actions	Date
10-day final ballot	01/05/2017 – 01/16/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
   - **4.1. Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Balancing Authority
     - **4.1.3.** Transmission Owner
     - **4.1.4.** Transmission Operator
     - **4.1.5.** Generator Owner
     - **4.1.6.** Generator Operator
     - **4.1.7.** Distribution Provider
5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Plan within 24 hours or by the end of the next business day, as applicable.	Plan within 24 hours or by the end of the next business day, as applicable.	Plan within 24 hours or by the end of the next business day, as applicable.	within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction	TOP	System-wide voltage reduction of 3% or more to maintain the continuity of the BES.
Firm load shedding resulting from a BES Emergency	Initiating RC, BA, TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form

Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."

	Task	Comments
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to its Facility ☐ Physical Threat to its BES control center ☐ System-wide voltage reduction ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		Comments
	☐ System separation (islanding) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

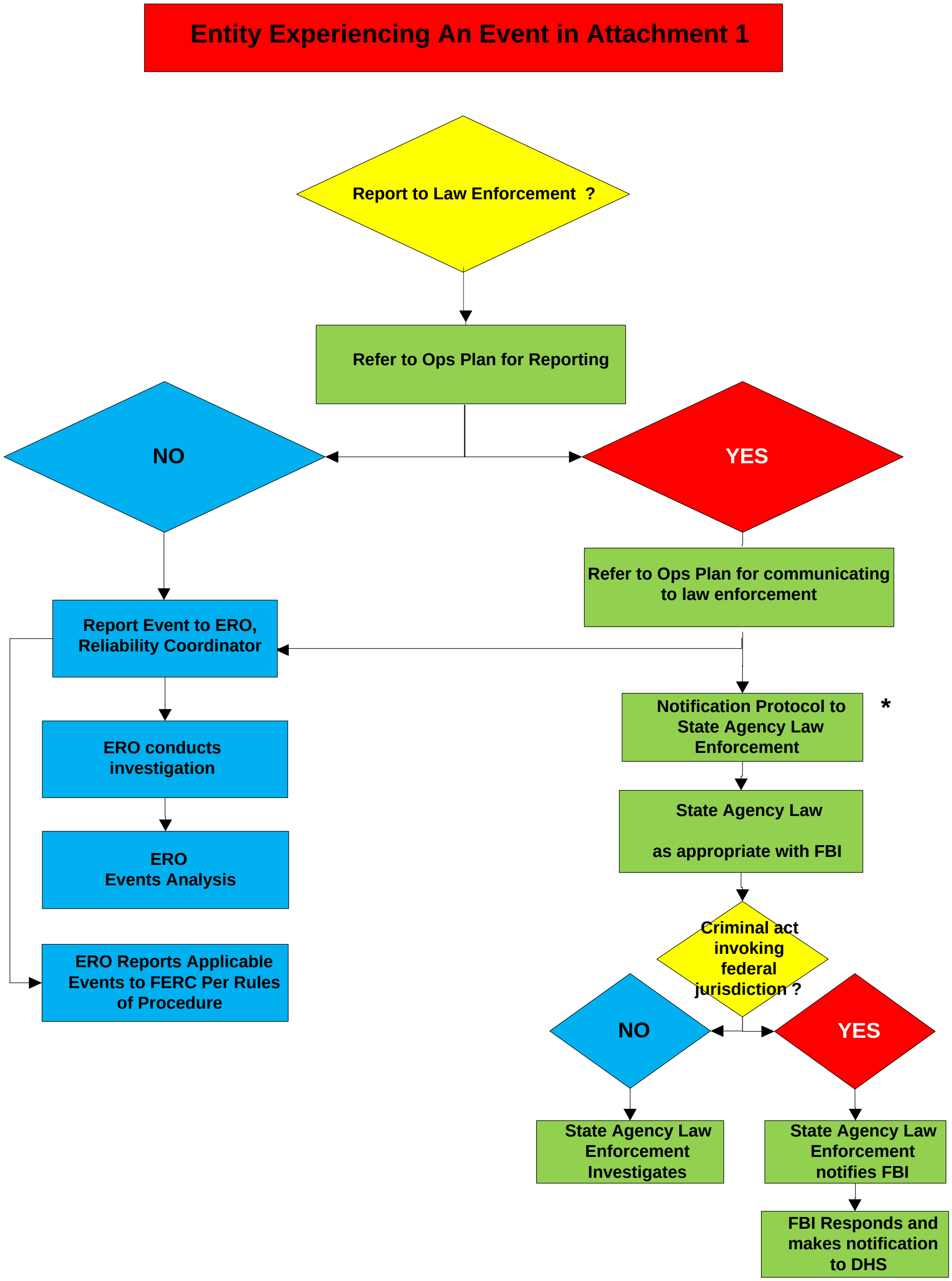
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/06/2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~07/25/2016 – 09/08/2016~~
~~45-day formal comment period with additional ballot~~	~~09/26/2016 – 11/09/2016~~
10-day final ballot	~~12~~01/~~01~~11/~~2016~~ 2017 – ~~12~~01/~~12~~20/~~2016~~2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

    4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following ~~functional~~ Functional ~~entities~~ Entities will be collectively referred to as "Responsible Entity."

    4.1.1. Reliability Coordinator

    4.1.2. Balancing Authority

    4.1.3. Transmission Owner

    4.1.4. Transmission Operator

    4.1.5. Generator Owner

    4.1.6. Generator Operator

    4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes~~, but is not limited to the~~ protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of ~~within~~ 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's ~~-~~next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday)~~ (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of ~~within~~ 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day) ~~of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday)~~.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.

- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Plan within 24 hours or by the end of the next business day, as applicable.	Plan within 24 hours or by the end of the next business day, as applicable.	Plan within 24 hours or by the end of the next business day, as applicable.	within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction ~~to maintain the continuity of the BES~~	TOP	System-~~-~~wide voltage reduction of 3% or more to maintain the continuity of the BES.
Firm load shedding resulting from a BES Emergency	Initiating RC, BA, TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ ~~1,000~~1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES ~~Elements~~ Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center ~~evacuation~~	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at ~~a~~ its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting ~~a~~ its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at ~~a~~ its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at ~~a~~ its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
	Event Identification and Description:	

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780~~, Option 1~~. Also submit to other ~~applicable~~ organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**

4.	(Check applicable box)
	☐ Damage or destruction of a Facility
	☐ Physical Threat to its Facility
	☐ Physical Threat to its BES control center
	~~☐ Unplanned BES control center evacuation~~
	~~☐ Public appeal for load reduction~~
	☐ System-wide voltage reduction
	☐ BES Emergency:
	    ☐ firm load shedding
	    ☐ public appeal for load reduction
	    ☐ voltage deviation on a Facility
	    ☐ uncontrolled loss of firm load
	☐ System separation (islanding)
	☐ Generation loss
	☐ Complete loss of off-site power to a nuclear generating plant (grid supply)
		Written description (optional):

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	Task	**Comments**
	☐ Transmission loss ☐ Unplanned evacuation of its BES control center ~~evacuation~~ ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at ~~a~~ its staffed BES control center ☐ Complete loss of monitoring or control capability at ~~a~~ its staffed BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
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Guideline and Technical Basis

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Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
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- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

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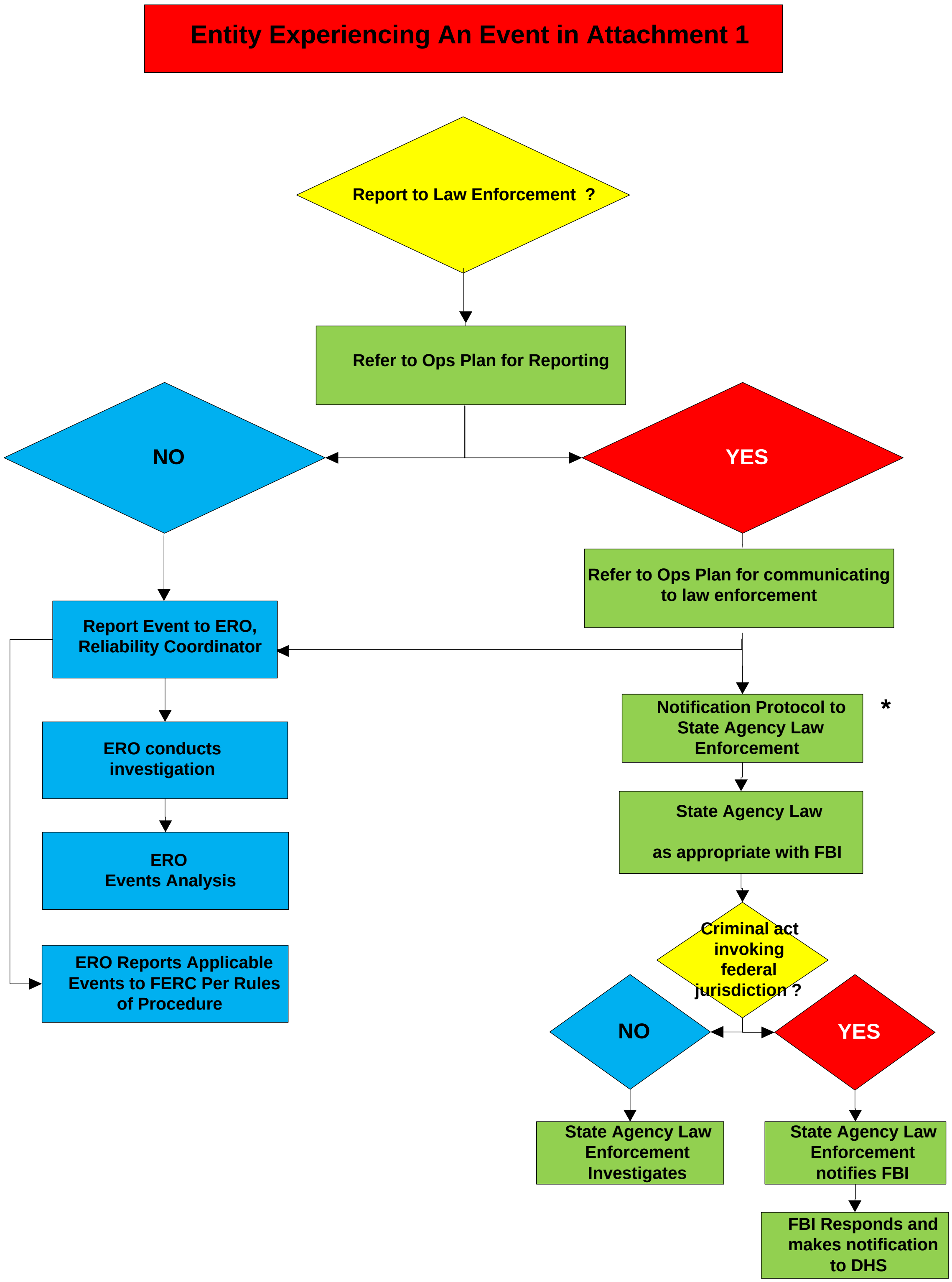

* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

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General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional ~~entities~~ Entities to report the incidents and provide ~~known~~ information ~~as~~ known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

Where approval by an Applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
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EOP-004-4 — Event Reporting

Where approval by an ~~applicable~~ Applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the ~~applicable~~ Applicable ~~governmental~~ Governmental ~~authority~~Authority.

Where approval by an ~~applicable~~ Applicable ~~governmental~~ Governmental ~~authority~~ Authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

2015-08 Emergency Operations – EOP-004-4

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Operations; EOP-004-4 – Event Reporting**. The electronic form must be submitted by **8 p.m. Eastern, Friday, January 6, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email), or at (404) 446-9671.

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT), including the recommendation to revise EOP-004-3 Attachment 1, and retire Requirement R3.[1] The EOP standards drafting team (SDT) considered those recommendations, along with additional input from the industry during the comment period on the project Standard Authorization Request (SAR) for this project. Additionally, the SDT has entered into collaborative efforts among NERC and the U.S. Department of Energy (DOE) to better align reporting requirements pursuant to EOP-004-3 and OE-417. Based on those inputs, the SDT proposes the changes to EOP-004-3 as indicated in this posting.

With respect to DOE collaboration, the SDT has discussed with DOE changes that would be necessary to EOP-004 Attachment 1 and to OE-417 to more closely align EOP-004-4 Attachment 1 Reportable Events with events reported on OE-417. Based on those discussions and the changes proposed in this posting, the SDT and DOE have made significant progress in harmonizing reporting requirements, which would relieve many entities from having to report Reportable Events on both forms. That collaboration continues, but it is important to note that **regardless of whether OE-417 is harmonized with EOP-004-4 Attachment 1, entities will be required to report all Reportable Events as required by EOP-004-4**.

The EOP SDT recommends the following changes to EOP-004-3:

- Update and clarify language in Requirements R1 and R2
- Retire Requirement R3
- Revise Attachment 1: Reportable Events and Attachment 2: Event Reporting Form

[1] The review included EOP-004-3, EOP-005-2, EOP-006-2 and EOP-008-1 to evaluate, for example, whether the requirements are clear and unambiguous. Recommended revisions to EOP-005-2, EOP-006-2, and EOP-008-1 have been posted for comment and ballot in a separate posting.

Update and Clarify Requirements R1 and R2

The SDT proposes a conforming edit in Requirement R1 to reference the correct version number of EOP-004-4 assuming EOP-004-4 ultimately is approved. Specifically, reference to "EOP-004-3" has been changed to "EOP-004-4." That conforming change also is made to Measure M1.

The SDT proposes to clarify in Requirement R2 that each Responsible Entity shall report events "specified in EOP-004-4 Attachment 1 to the entities specified" in its Operating Plan. The SDT proposes this addition to ensure the Responsible Entity is reporting on the event types and thresholds from EOP-004-4 Attachment 1. Additionally, the SDT proposes to clarify what constitutes a weekend for the purpose of implementing the requirement, i.e., "4 PM local time will be considered the end of the business day)." The SDT proposes similar language and additional clarifications in Measure M2.

Retire Requirement R3

The SDT recommends retiring Requirement R3 under Criterion B1, administrative, because it requires responsible entities to perform a function that is administrative in nature, does not support reliability, and is needlessly burdensome. The SDT notes that contact lists are administrative in nature and should not be part of a mandatory reliability standard.

Revise Attachment 1: Reportable Events and Attachment 2: Event Reporting Form

The SDT proposes several changes to the Event Type, Entity with Reporting Responsibility, and Threshold for Reporting in response to SAR comments and its own analyses. The SDTs changes intend to: clarify appropriate Responsible Entity responsibilities; eliminate duplicative reporting by the Generator Operator (GOP) and Balancing Authority (BA); clarify Generation loss criteria specific to Quebec Interconnection and ERCOT Interconnection; and align reporting requirements OE-417 where appropriate. The SDT provided its reasoning in the redlined standard.

The SDT proposes several changes to Attachment 2 to clarify to whom the Event Reporting Form should be submitted and to more appropriately describe the "Event Identification and Description" field on the form.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

4. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

   Comments:

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R2 **R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time).	EOP-004-04, Requirement R2 **R2.** Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	Requirement R2 revisions were to provide for clarity; to remove the ambiguity for weekends and to add clarity for holidays.
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Attachment 1 Event Type: Damage or destruction of a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action.	EOP-004-04, Attachment 1 Event Type: Damage or destruction of its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-03, Attachment 1 Event Type: Physical threats to a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster	EOP-004-04, Attachment 1 Event Type: Physical threats to its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.	"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-03, Attachment 1 Event Type: Physical threats to a BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.	EOP-004-04, Attachment 1 Event Type: Physical threats to its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.	With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
OR Suspicious device or activity at a BES control center.	OR Suspicious device or activity at its BES control center.	
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring public appeal for load reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Public appeal for load reduction event.	EOP-004-04, Attachment 1 Event Type: Public appeal for load reduction resulting from a BES Emergency Entity with Reporting Responsibility: BA Threshold for Reporting: Public appeal for load reduction to maintain continuity of the BES.	To maintain the continuity of the BES was added to better align with the DOE OE-417 reporting category. Rationale: The EOP SDT changed the reporting responsibility to the BA only based on the BA requirements in EOP-011-1 (FERC approved, pending enforcement) Requirement R2 "Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		2.2. Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions;
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring system-wide voltage reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting	EOP-004-04, Attachment 1 Event Type: System-wide voltage reduction Entity with Reporting Responsibility: TOP Threshold for Reporting: System-wide voltage reduction of 3% or more to maintain the continuity of the BES.	The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: System wide voltage reduction of 3% or more.		
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring manual firm load shedding Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Manual firm load shedding ≥ 100 MW.	EOP-004-04, Attachment 1 Event Type: Firm load shedding resulting from a BES Emergency Entity with Reporting Responsibility: Initiating RC, BA, TOP Threshold for Reporting: Firm load shedding ≥ 100 MW (manual or automatic).	The RC, BA and TOP are the entities that would initiate manual firm load shedding.
EOP-004-03, Attachment 1 Event Type: BES Emergency resulting in automatic firm load shedding Entity with Reporting Responsibility: DP, TOP Threshold for Reporting: Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.
EOP-004-03, Attachment 1 Event Type: Voltage deviation on a Facility	EOP-004-04, Attachment 1	To provide clarity to the Event Type and to the Threshold for Reporting, the language revisions were made.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Entity with Reporting Responsibility: TOP Threshold for Reporting: Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	Event Type: BES Emergency resulting in voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: A voltage deviation of =/> ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	
EOP-004-03, Attachment 1 Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Entity with Reporting Responsibility: RC Threshold for Reporting: Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement. Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) are in the new standard TOP-001-3, Requirement R12 that becomes effective on 4/1/17, requiring a self-report if Tv is exceeded; the TOP-007-WECC-1 standard is pending retirement.
EOP-004-03, Attachment 1 Event Type: Loss of firm load Entity with Reporting Responsibility: BA, TOP, DP	EOP-004-04, Attachment 1 Event Type: Uncontrolled loss of firm load resulting from a BES Emergency	To provide clarity to the Threshold for Reporting and to align with the DOE's OE-417 reporting category, language revisions were made.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Loss of firm load for ≥ ≥ 300 MW for entities with previous yea 3,000 MW OR ≥ 200 MW for all other entities	Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities	
EOP-004-03, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA, GOP Threshold for Reporting: Total generation loss, within one minute, of : ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	EOP-004-04, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA Threshold for Reporting: Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection	The EOP SDT removed the reporting requirement from the GOPs to reduce redundant reporting. The BA should do the reporting given they have the generation status information. Technical justification for reverting back to the value of 2,000 MW for the generation loss for the Québec Interconnection and for harmonizing with NERC EA process. 1. Generation in the Québec Interconnection is 95 % hydraulic. To be efficient, generation must

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operate within 80 % of its operating range. There is a large spinning reserve available at all times which aids in the recovery period after an event (ACE-Area Control Error). Historically, the recorded average ACE recovery time for a 2,000 MW loss is 5 minutes which is 3 times faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. Based on the Hydro Québec's generation loss reports, generation loss between 1,500 MW to 2,000 MW does not trig the first stage threshold of the UFLS scheme. The frequency stayed above the underfrequency limit. 3. In order to maintain the integrity of the Québec system, the RPTC SPS in Québec (Generation Rejection and Remote Load Shedding) is designed to detect abnormal or

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		predetermined system conditions, to take corrective actions and to deliberately remove up to 1,500 MW of preselected generation from the power system. Consequently, the system is design to remain stable upon the instantaneous loss of 1,500 MW of generation. For Hydro-Québec, a generation loss of more than 2,000 MW is considered as an issue, which is make sense with previous 2,000 MW generation loss reporting requirement. 4. The EEA Level 3 alert (EOP-002) in Québec is set generally set at 2,000 MW, based on the deficiency of operating reserves and margins. Up to now, no EEA Level 3 alert has occurred in the Québec Interconnection. 5. Hydro Québec's loss of generation in first contingency (n-1) is set around 2,000 MW.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Technical justification for ERCOT 1,400 MW for the generation loss for the ERCOT Interconnection. 1. ERCOT maintains a mix of operating reserves (typically 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves) available at all times, which aids in the recovery period after an event affecting Area Control Error (ACE) or frequency. ERCOT typically procures between 2,300 MW to 3,000 MW of frequency responsive reserves for all operating hours besides procuring additional regulation and non-spinning reserves. The Load Resources controlled by Under-Frequency relay are set to respond automatically at 59.7 Hz to provide instantaneous frequency response. Historically, the recorded average ACE recovery time for a 1,400 MW

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		loss is less than 10 minutes, which is much faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. The design criteria for ERCOT's frequency responsive reserves is to procure adequate reserves that allow frequency to stay above the under-frequency limit for up to ERCOT's resource contingency criteria limit of 2,750 MW. 3. The EEA level 1 alert (EOP-002) in ERCOT is set at 2,300 MW of Physical Responsive Capability (PRC) which is a mix of operating reserves (typically 50% Load Resources and 50% frequency responsive spinning reserves).
EOP-004-03, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power affecting a nuclear generating	EOP-004-04, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP	The Event Analysis Program (EAP) refers to loss of off-site power as "(LOOP)". Therefore, LOOP has been added to the Threshold for Reporting to provide consistency.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
station per the Nuclear Plant Interface Requirement	Threshold for Reporting: Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirement	
EOP-004-03, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	EOP-004-04, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).	The definition of BES Element includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event Type. It could lead to confusion as to the element count for three elements contrary to design. In addition, the EAP uses the definition of "BES Facility" in its application, which could lead to additional confusion in evaluating a reporting during an event. The EOP SDT revised "BES Elements" to "BES Facilities" to add clarity to the Threshold for Reporting and to align with the EAP language.
EOP-004-03, Attachment 1 Event Type: Unplanned BES control center evacuation	EOP-004-04, Attachment 1 Event Type: Unplanned evacuation of its BES control center	In the Threshold for Reporting, with the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.	
EOP-004-03, Attachment 1 Event Type: Complete loss of voice communication capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.	EOP-004-04, Attachment 1 Event Type: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.	COM-001-2 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." And Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."
EOP-004-03, Attachment 1 Event Type: Complete loss of monitoring capability	EOP-004-04, Attachment 1 Event Type: Complete loss of monitoring or control capability at its staffed BES control center	The language revisions to this event type provides clarity to the Threshold for Reporting and better aligns with the EAP language.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.	

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R2 **R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time).	EOP-004-04, Requirement R2 **R2.** Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	Requirement R2 revisions were to provide for clarity; to remove the ambiguity for weekends and to add clarity for holidays.
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Attachment 1 Event Type: Damage or destruction of a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action.	EOP-004-04, Attachment 1 Event Type: Damage or destruction of its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-03, Attachment 1 Event Type: Physical threats to a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster	EOP-004-04, Attachment 1 Event Type: Physical threats to its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.	"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-03, Attachment 1 Event Type: Physical threats to a BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.	EOP-004-04, Attachment 1 Event Type: Physical threats to its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.	With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
OR Suspicious device or activity at a BES control center.	OR Suspicious device or activity at its BES control center.	
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring public appeal for load reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Public appeal for load reduction event.	EOP-004-04, Attachment 1 Event Type: Public appeal for load reduction resulting from a BES Emergency Entity with Reporting Responsibility: BA Threshold for Reporting: Public appeal for load reduction to maintain continuity of the BES.	To maintain the continuity of the BES was added to better align with the DOE OE-417 reporting category. Rationale: The EOP SDT changed the reporting responsibility to the BA only based on the BA requirements in EOP-011-1 (FERC approved, pending enforcement) Requirement R2 "Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		2.2. Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions;
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring system-wide voltage reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting	EOP-004-04, Attachment 1 Event Type: System-wide voltage reduction Entity with Reporting Responsibility: TOP Threshold for Reporting: System-wide voltage reduction of 3% or more to maintain the continuity of the BES.	The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: System wide voltage reduction of 3% or more.		
EOP-004-03, Attachment 1 Event Type: BES Emergency requiring manual firm load shedding Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Manual firm load shedding ≥ 100 MW.	EOP-004-04, Attachment 1 Event Type: Firm load shedding resulting from a BES Emergency Entity with Reporting Responsibility: Initiating RC, BA, TOP Threshold for Reporting: Firm load shedding ≥ 100 MW (manual or automatic).	The RC, BA and TOP are the entities that would initiate manual firm load shedding.
EOP-004-03, Attachment 1 Event Type: BES Emergency resulting in automatic firm load shedding Entity with Reporting Responsibility: DP, TOP Threshold for Reporting: Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.
EOP-004-03, Attachment 1 Event Type: Voltage deviation on a Facility	EOP-004-04, Attachment 1	To provide clarity to the Event Type and to the Threshold for Reporting, the language revisions were made.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Entity with Reporting Responsibility: TOP Threshold for Reporting: Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	Event Type: BES Emergency resulting in voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: A voltage deviation of =/> ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	
EOP-004-03, Attachment 1 Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Entity with Reporting Responsibility: RC Threshold for Reporting: Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement. Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) are in the new standard TOP-001-3, Requirement R12 that becomes effective on 4/1/17, requiring a self-report if Tv is exceeded; the TOP-007-WECC-1 standard is pending retirement.
EOP-004-03, Attachment 1 Event Type: Loss of firm load Entity with Reporting Responsibility: BA, TOP, DP	EOP-004-04, Attachment 1 Event Type: Uncontrolled loss of firm load resulting from a BES Emergency	To provide clarity to the Threshold for Reporting and to align with the DOE's OE-417 reporting category, language revisions were made.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Loss of firm load for ≥ ≥ 300 MW for entities with previous yea 3,000 MW OR ≥ 200 MW for all other entities	Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities	
EOP-004-03, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA, GOP Threshold for Reporting: Total generation loss, within one minute, of : ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	EOP-004-04, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA Threshold for Reporting: Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection	The EOP SDT removed the reporting requirement from the GOPs to reduce redundant reporting. The BA should do the reporting given they have the generation status information. Technical justification for reverting back to the value of 2,000 MW for the generation loss for the Québec Interconnection and for harmonizing with NERC EA process. 1. Generation in the Québec Interconnection is 95 % hydraulic. To be efficient, generation must

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operate within 80 % of its operating range. There is a large spinning reserve available at all times which aids in the recovery period after an event (ACE-Area Control Error). Historically, the recorded average ACE recovery time for a 2,000 MW loss is 5 minutes which is 3 times faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. Based on the Hydro Québec's generation loss reports, generation loss between 1,500 MW to 2,000 MW does not trig the first stage threshold of the UFLS scheme. The frequency stayed above the underfrequency limit. 3. In order to maintain the integrity of the Québec system, the RPTC SPS in Québec (Generation Rejection and Remote Load Shedding) is designed to detect abnormal or

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		predetermined system conditions, to take corrective actions and to deliberately remove up to 1,500 MW of preselected generation from the power system. Consequently, the system is design to remain stable upon the instantaneous loss of 1,500 MW of generation. For Hydro-Québec, a generation loss of more than 2,000 MW is considered as an issue, which is make sense with previous 2,000 MW generation loss reporting requirement. 4. The EEA Level 3 alert (EOP-002) in Québec is set generally set at 2,000 MW, based on the deficiency of operating reserves and margins. Up to now, no EEA Level 3 alert has occurred in the Québec Interconnection. 5. Hydro Québec's loss of generation in first contingency (n-1) is set around 2,000 MW.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Technical justification for ERCOT 1,400 MW for the generation loss for the ERCOT Interconnection. 1. ERCOT maintains a mix of operating reserves (typically 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves) available at all times, which aids in the recovery period after an event affecting Area Control Error (ACE) or frequency. ERCOT typically procures between 2,300 MW to 3,000 MW of frequency responsive reserves for all operating hours besides procuring additional regulation and non-spinning reserves. The Load Resources controlled by Under-Frequency relay are set to respond automatically at 59.7 Hz to provide instantaneous frequency response.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Historically, the recorded average ACE recovery time for a 1,400 MW loss is less than 10 minutes, which is much faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. The design criteria for ERCOT's frequency responsive reserves is to procure adequate reserves that allow frequency to stay above the under-frequency limit for up to ERCOT's resource contingency criteria limit of 2,750 MW. 3. The EEA level 1 alert (EOP-002) in ERCOT is set at 2,300 MW of Physical Responsive Capability (PRC) which is a mix of operating reserves (typically 50% Load Resources and 50% frequency responsive spinning reserves).

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	EOP-004-04, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirement	The Event Analysis Program (EAP) refers to loss of off-site power as "(LOOP)". Therefore, LOOP has been added to the Threshold for Reporting to provide consistency.
EOP-004-03, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	EOP-004-04, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).	The definition of BES Element includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event Type. It could lead to confusion as to the element count for three elements contrary to design. In addition, the EAP uses the definition of "BES Facility" in its application, which could lead to additional confusion in evaluating a reporting during an event. The EOP SDT revised "BES Elements" to "BES Facilities" to add clarity to the Threshold for Reporting and to align with the EAP language.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Attachment 1 Event Type: Unplanned BES control center evacuation Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	EOP-004-04, Attachment 1 Event Type: Unplanned evacuation of its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.	In the Threshold for Reporting, with the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…BES control center" to "…its BES control center."
EOP-004-03, Attachment 1 Event Type: Complete loss of voice communication capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.	EOP-004-04, Attachment 1 Event Type: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.	COM-001-2 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." And Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Attachment 1 Event Type: Complete loss of monitoring capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	EOP-004-04, Attachment 1 Event Type: Complete loss of monitoring or control capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.	The language revisions to this event type provides clarity to the Threshold for Reporting and better aligns with the EAP language.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were slightly revised to add "event reporting." The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their event reporting Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their event reporting Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were ~~not~~ slightly revised to add "event reporting." The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their event reporting Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their event reporting Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable..

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement

Project 2015-08 Emergency Operations
EOP-004-4

Formal Comment Period Open through January 6, 2017

Now Available

A 45-day formal comment period for **EOP-004-4 – Event Reporting** is open through **8 p.m. Eastern, Friday, January 6, 2017.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted December 28 – January 6, 2017.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/72)
Ballot Name: 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 AB 2 ST
Voting Start Date: 12/28/2016 12:01:00 AM
Voting End Date: 1/9/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 271
Total Ballot Pool: 340
Quorum: 79.71
Weighted Segment Value: 93.55

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	65	0.942	4	0.058	0	3	17
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	75	1	52	0.929	4	0.071	0	2	17
Segment: 4	23	1	18	0.947	1	0.053	0	0	4
Segment: 5	84	1	58	0.921	5	0.079	0	0	21
Segment: 6	45	1	36	0.923	3	0.077	0	0	6
Segment: 7	3	0.1	1	0.1	0	0	0	1	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.7	7	0.7	0	0	0	1	1
Totals:	340	6.8	246	6.362	18	0.438	0	7	69

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		None	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Aaron Austin		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Dehn Stevens		None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		None	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Empire District Electric Co.	Michael kidwell		None	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		None	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 340 of 340 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/72)
Ballot Name: 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 NBP AB 2 NB
Voting Start Date: 12/28/2016 12:01:00 AM
Voting End Date: 1/9/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 252
Total Ballot Pool: 318
Quorum: 79.25
Weighted Segment Value: 95.05

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	83	1	49	0.961	2	0.039	16	16
Segment: 2	7	0.4	3	0.3	1	0.1	2	1
Segment: 3	74	1	43	0.956	2	0.044	11	18
Segment: 4	21	1	13	1	0	0	4	4
Segment: 5	76	1	45	0.938	3	0.063	8	20
Segment: 6	41	1	27	0.931	2	0.069	8	4
Segment: 7	3	0.1	1	0.1	0	0	1	1
Segment: 8	3	0.3	3	0.3	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	9	0.8	8	0.8	0	0	0	1
Totals:	318	6.6	192	6.285	10	0.315	50	66

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		None	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Aaron Austin		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Dehn Stevens		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		None	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Francis Halpin		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Abstain	N/A
5	Orlando Utilities Commission	Richard Kinas		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		None	N/A
5	Westar Energy	Laura Cox		None	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 318 of 318 entries

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations
EOP-004-4

Formal Comment Period Open through January 6, 2017

Now Available

A 45-day formal comment period for **EOP-004-4 – Event Reporting** is open through **8 p.m. Eastern, Friday, January 6, 2017.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted December 28 – January 6, 2017.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-08 Emergency Operations | EOP-004-4
Comment Period Start Date:	11/18/2016
Comment Period End Date:	1/9/2017
Associated Ballots:	2015-08 Emergency Operations | EOP-004-4 EOP-004-4 AB 2 ST 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 NBP AB 2 NB

There were 38 sets of responses, including comments from approximately 33 different people from approximately 31 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

2. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Bill Watson	Old Dominion Electric Cooperative	3,4	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Matt Caves	Western Farmers Electric Cooperative	1,5	SPP RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Con Ed - Consolidated	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC

Edison Co. of New York					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC

					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO

					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Colorado Springs Utilities	Shannon Fair	6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					James Nail	Independence Power and Light	3	SPP RE
					Tara Lightner	Sunflower Electric	1	SPP RE
					Robert Gray	Board of Public Utilities (BPU) Kansas City, KS	3	SPP RE
					Leo Bernier	AES	NA - Not Applicable	NA - Not Applicable
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Sean Simpson	Board of Public Utilities, Kansas City, KS	3	SPP RE

					Tony Eddlement	Nebraska Public Power District	1,3,5	SPP RE

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests clarification on the addition of "by the later of" and the use of 4pm as the end of a business day. Is it the drafting team's intent that the Responsible Entity has the option of submitting an Event Report 24 hours after the Event threshold has been reached, or the entity may choose to submit the report later than the 24 hours, as long as the report is submitted by 4pm the next business day? The proposed language as currently written may create some ambiguity depending on the reader.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
As stated in the comments with the initial ballot, Texas RE noticed there is no requirement specifically indicating how events should be reported. Additionally, the VSLs indicate that a verbal report is acceptable. Since an event reporting form exists, Texas RE recommends the requirements specify the form in Attachment 2 be used for event reporting. In the Severe VSL for R2 "-4_ should be added to the last sentence to maintain consistency (e.g. "EOP-004-4").	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **"Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2"** is stated in Attachment 1 of the standard. The VSL for Requirement R2 has been updated: "The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1."	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	No
Document Name	

Comment

(1) We thank the SDT for the development of this draft standard revision and the removal of the administrative burden reflected in Requirement R3 of the current standard. While we generally agree with the results-based compliance approach presented in this draft, we feel that the SDT has an opportunity to further clarify the intentions of their proposed changes.

(2) We believe Requirement R2 is intended to provide the Responsible Entity an option of using the criterion that will occur last when reporting. While either criterion will occur "later" from the initial event discovery, as used in the context of an adverb describing a point in time, the ability to select one criterion versus the other is an adjective that describes the criteria's comparison. We recommend using "…by the latter of…" in the requirement text instead.

(3) The first criterion listed in Requirement R2 states "24 hours of recognition of meeting an event type threshold for reporting." We believe the SDT inadvertently removed a necessary and supportive phrase that identifies the duration of the criterion. We also believe the SDT failed to establish a starting trigger for this criterion with the recognition and discovery of the event. We recommend rewording the criterion to read "within 24 hours following recognition of meeting an event type threshold for reporting."

(4) The second criterion listed in Requirement R2 identifies the end of a business day as 4:00 PM. What is the rationale for selecting an arbitrary time? How do joint-filing entities that operate across large geographic regions and multiple time zones identify the local time? How does a single entity with centralized operations in one time zone identify local time for an event originating in a different time zone? We agree with the SDT's intent to remove ambiguity regarding weekends and holidays, but believe the addition of the 4:00 PM local time reference creates unintended confusion. We recommend removing the reference entirely and allow some flexibility for the Responsible Entity to define its own meaning of "next business day." This would allow smaller entities, with a limited impact on BES reliability, to report after an extended weekend and after becoming fully staffed.

(5) To clearly delineate the possible criteria available for Requirement R2, we believe each criterion should be renumbered into individual subparts list.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day (4:00 pm was selected because it is a typical ending time for operating personnel). The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of the next business day based on the local time of the entity's centralized location. The Responsible Entity could document this in their event reporting Operating Plan.

Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes that the R2 language should only refer to required event reporting to Operating Plan entities (e.g. NERC and/or DOE) within the reporting period.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The EOP SDT finds that the Responsible Entity can define who the entities they report are within their event reporting Operating Plan.	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
The VSLs for R2 need to reflect the change in reporting deadlines to accommodate the reporting entity's next business day	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the VSLs for Requirement R2.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
To clarify the Standard pertains to Event Reporting, Reclamation respectfully proposes the following revised language for Standard EOP-004-4, R1, R2, M1, and M2: R1. : Each Responsible Entity shall have an Event Reporting Operating Plan that includes the protocol(s) for reporting the Reportable Events listed in EOP-004-4 Attachment 1 to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, Responsible Entity personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). Reclamation suggests re-wording M1 as follows: Each Responsible Entity will have a dated Event Reporting Operating Plan that includes the reporting protocol(s) and name(s) of organization(s) to receive an event report for the Reportable Event(s) specified in EOP-004-4 Attachment 1. R2. Each Responsible Entity shall report the types of events specified in EOP-004-4 Attachment 1, to the entities specified per its Event Reporting Operating Plan, by the later of 24 hours after recognition of meeting an event type threshold or by the end of the Responsible Entity's next business day, whichever is later (4 p.m. local time will be considered the end of the business day). M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within the timeframes identified in R2 above. Reclamation suggests the following change to both R2 and M2: "by the later of 24 hours after recognition of meeting an event type…"	
Likes 0	

Dislikes 0	

Response

Thank you for your comments. The EOP SDT finds the language in Requirement R1 and Measure M1 is clear as written and it does not require the specifics you are asking for in your suggested language.

Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day. The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of the next business day based on the local time of the entity's centralized location. The Responsible Entity could document this in their event reporting Operating Plan.

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF would like to thank the Standard Drafting Team (SDT) for their thoughtful changes and believes the revisions proposed are valuable. Please see question two for concerns that we have.

Likes 0	
Dislikes 0	

Response

Thank you for your support. Please see responses to Question 2.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

With regard to requirement R2, AZPS recommends modifying the text for clarity to read as "the later of 24 hours following recognition of meeting an event type" as opposed to "the later of 24 hours of recognition of meeting an event type."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day. The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of

the next business day based on the local time of the entity's centralized location. The Responsible Entity could document this in their event reporting Operating Plan.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
As for Requirement R1, we have no concerns pertaining to the proposed changes. However, we feel the clarity notes applicable to Measurement M1 in the comment form are inaccurate (page 2). The notes mentions the correction to the version number however, it doesn't mention the phrase **"but is not limited to the"** being stricken from the standard. We suggest the drafting team update all applicable documents to reflect that change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the Mapping Document.	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
WAPA appreciates the efforts of the Standards Drafting Team (SDT) and welcomes the changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - Andrew Pusztai

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tony Eddleman - Nebraska Public Power District - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

2. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	ERO_EAP_Documents DL-Justification_for_Event_Category_1g_and_3a_changes_for_ERCOT.pdf

Comment

ERCOT appreciates the SDT revising the generation loss reporting threshold for the ERCOT Interconnection to 1,400 MW from 1,000 MW in Attachment 1 of EOP-004. This change is consistent with ERCOT's September 8, 2016 comments, which requested this revision to align the reporting threshold with the *ERO Event Analysis Process* (EAP) document's threshold for initiating an analysis of a Category 3a generation loss event in the ERCOT Interconnection, which, at the time of ERCOT's comment, was 1,400 MW.

However, concurrent with Project 2015-08, the NERC Event Analysis Subcommittee (EAS) proposed changes to the EAP document that, among other things, sought to standardize the event analysis threshold for all Interconnections—including ERCOT—at 2,000 MW. The draft EAP document was first posted for comment on the NERC website on September 30, 2016, some three weeks after ERCOT submitted its comments to the latest version of EOP-004. The revised EAP document—version 3.1—was ultimately approved by the NERC Operating Committee at its December 13, 2016 meeting and became effective January 1, 2017. Thus, the threshold for conducting an analysis of Category 3a events is now 2,000 MW.

Consistent with ERCOT's September 8 comments and with the SDT's change to the reporting threshold in the last version of the draft standard, ERCOT believes the threshold for generation loss reporting in EOP-004 should continue to align with the EAP document's threshold for analysis of Category 3a events, which is now 2,000 MW. If there are any reasons for differentiating between the two thresholds, this justification does not seem immediately obvious. Fundamentally, in ERCOT's view, it would make little sense to require development of a written report of a generation loss event and distribute it to various entities if the event did not also justify an analysis under the EAP process. Furthermore, the reasons cited by the EAS for increasing the event analysis threshold—the implementation of BAL-003-1.1 and BAL-001-TRE-01, and the procurement of greater quantities of responsive reserve in ERCOT, among other reasons—would also appear to justify increasing the event reporting threshold. See *Justification for Proposed Changes to the ERO Event Analysis Process Categories 1g and 3a* (attached).

In conclusion, ERCOT appreciates the SDT's recognition of the need to align the EOP-004 generation loss reporting threshold with the EAP document's generation loss event analysis threshold and asks the SDT to continue this alignment by setting the generation loss reporting threshold for the ERCOT Interconnection in EOP-004 Attachment 1 to 2,000 MW.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. To establish the equitable criteria for reporting in the ERCOT interconnection, the EOP SDT has revised the reporting threshold from 1,000 MW to 1,400 MW for generation loss in the ERCOT interconnection, as recommended from the September comments. Please refer to the project's mapping document for the technical justification regarding this revision. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The reporting threshold for generation loss in the ERCOT Interconnection in proposed EOP-004-4 is aligned with the DOE OE-417.

Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes that the BA or TOP could be the initiating parties for a load appeal. Also, more clarity should be added for automatic load shedding causes (UVLS, UFLS, RAS).

Likes 0	
Dislikes 0	

Response

Thank you for your comments. EOP-011-1 puts the responsibility of having public appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. The EOP SDT feels that the Threshold for Reporting is clear, the Responsible Reporting Entity will know if the Firm load shedding was done either manually, automatically or a combination of both.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion

Answer	No
Document Name	

Comment

For the "Complete loss of monitoring or control capability at its staffed BES control center" Event Type, the "Threshold for Reporting" column should be revised as follows: "Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more, such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable." The "Threshold for Reporting" language should continue to include the "such that […]" language to maintain consistency with the EAP.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The EOP SDT has discussed your comment but finds that the Event Type and Threshold for Reporting are clear as written.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No

Document Name	
Comment	

Texas RE appreciates the SDT's response to Texas RE's previous comments regarding the removal of the IROLTV reporting obligation. As the SDT noted in its response, the SDT removed the reporting requirement because the new TOP-001-3 R12 requirement requires registered entities to avoid exceeding IROLs for the relevant TV period. As such, the SDT reasons that entities will self-report any noncompliance and there is no need to retain the corresponding reporting requirement.

Texas RE sees two issues with the SDT's rationale. First, as Texas RE noted in its original comments, there is a significant difference in the purpose and timing of the EOP-004 reporting requirements and the substantive obligations set forth under the new TOP-001-3, R12. Texas RE noted: "While such an exceedance may be investigated in the compliance or enforcement process, there is necessarily a delay in these activities. The contemporaneous reporting obligations serve to ensure that the NERC regions have immediate knowledge that a significant risk of a cascading outage has occurred, permitting the region to begin steps to identify the root cause and develop appropriate mitigation. Because such awareness appears critical to the core reliability functions performed within the NERC regions, Texas RE cautions against eliminating this requirement." Simply put, the mere existence of a parallel substantive requirement does not address Texas RE's concern. Texas RE cannot support the elimination of the IROLTV reporting obligation based on the SDT's proffered rationale.

Second, the SDT appears to misunderstand the self-reporting process. Principally, entities are under no obligation to self-report potential noncompliance instances, and may elect not to do so at their sole discretion. Given that certain utilities are on three- or even six-year audit cycles, an entity could decline to self-report an IROL exceedance violating TOP-001-3, R12 and wait until its next scheduled audit (contingent on the requirement being included in the audit scope). Accordingly, a potential issue could linger for years before it is addressed in the enforcement process. This is precisely the reason Texas RE believes the contemporaneous reporting requirement continues to be a necessary part of the NERC Reliability Standards.

Texas RE also suggests the Standard is too narrow in its reporting requirements for events. According to the Events Analysis Process effective January 1, 2017, "The primary reason for participating in an event analysis is to determine if there are lessons to be learned and shared with the industry. The analysis process involves identifying what happened, why it happened, and what can be done to prevent reoccurrence." Texas RE recommends broadening the requirements in order to understand prevention as well as what took place when event actually occurred. Texas RE provides the following suggestions for broadening the reporting requirements.

- Public appeal for load reduction should not be limited to a BES Emergency. In some cases the appeal may be done to avoid a BES Emergency and that event should be evaluated per the Events Analysis Process in order to prevent issues from occurring in the future.

- As previously submitted in comments with the initial ballot, Texas RE recommends adding the TOP function to the public appeal event type. This will align and be consistent with EOP-001-2.1b Requirement R2, which requires a TOP to "Develop, maintain, and implement a set of plans for load shedding", EOP-001-2.1b Requirement R3, which requires a TOP emergency plan to include "Load reduction", and EOP-001-2.1b Requirement R4, which references elements in Attachment 1-EOP-001 that a TOP and BA should consider when developing emergency plans.

- For the event types, "Complete loss of monitoring or control capability at its staffed BES control center" and "Complete loss of Interpersonal Communications and Alternative Interpersonal Communication capability at its staffed BES control center", Texas RE recommends removing "its staffed". Loss of monitoring or control capability is just as important at a non-staffed site as it is a staffed site and there should be no distinction in staffing status. Understanding why complete loss of monitoring or control capability and complete loss of Interpersonal and Alternative Interpersonal Communications occurred will increase the likelihood of prevention in the future.

Reliability Standard EOP-004-2 does not take into account GOP Control Centers. As previously stated, Texas RE recommends adding the GOP to the entity with reporting responsibility. Reliability Standard CIP-002-5 states that "each Control Center or back up Control Center used to perform the functional obligations of the Generator Operator" (CIP-002-5, Attachment 1, Sections 1.4 and 2.11) should be considered in an entity's identification of high and medium BES Cyber Systems. Reliability Standard CIP-008-5 Requirement 1 requires Responsible Entities with High and Medium Impact BES Cyber Systems (which could include GOP Control Centers) to have a process to determine if a Cyber Security Incident is reportable and noticed the E-ISAC. Since this includes GOP Controls Centers, it would be consistent to include GOP Control Centers in EOP-004-4. Also, there are several GOPs in Texas (and other regions) that may control more megawatts than some BAs and yet there is no requirement to report events that occur so they are studied and preventative measures are taken in the future. Since CIP-002-5 has a mechanism for considering GOP Control Centers, and there are several GOP Control Centers that may control as much or more generation than a BA, Texas RE recommends adding the GOP as an entity with reporting responsibility. From a consistency and reliability stand point, events that occur at a GOP Control Center should be reported on and evaluated.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The EOP SDT has discussed your concerns and still contends that IROL reporting should be removed from this standard. TOP-001-3, Requirement R12 becomes effective 4/1/17, requiring a self-report if Tv is exceeded; TOP-007-WECC-1 is pending retirement; IRO-009-2, Requirement R3, requires the RC to act or direct others to act until the IROL exceedance is mitigated with in the IROL's Tv. The EAP also lists Category 2 "…g.) Interconnection Reliability Operating Limit (IROL) Violation for the time greater than Tv." EOP-004 is not the proper vehicle for immediate reporting. The drafting team suggests following the standard development process of submitting a SAR for modification.

The purpose of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary, data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417.

Public appeal for load reduction in a BES Emergency is in the currently-enforced EOP-004 standard, the EOP SDT finds the Event Type is appropriate as written.

In Reliability Standard EOP-011-1 (subject to future enforcement, retires EOP-001-2.1b, EOP-002-3.1, and EOP-003-2), Requirement R2, it is the function of the BA to include within its RC-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies public appeals for voluntary load reductions (Requirement R2, Part 2.2.4.). The BA is the proper Entity with reporting responsibility for public appeal for load reduction resulting in a BES Emergency.

The EOP SDT team reviewed your comment about removing “its staffed” related to monitoring or control and Interpersonal/Alternative Interpersonal Communications. The team held many discussion on this topic related to staffed or not staffed; and, yes, it is important to the capability there, but if the site is not staffed the responsible entity will not be aware of the issue plus if you are not actively operating from the site there is no impact on reliability. The team is sure once the issues are identified the Responsible Entity will resolve the situation.

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

We suggest that the Event Type **“Transmission Loss”** in Attachment 1 be removed from this section of the document. We feel that this effort is redundant and has been addressed in the NERC Event Analysis Program. Our first example would be applicable to, the renewable generation such as wind farms would require reporting for the loss of three or more generators pertain to a Misoperations. Another example would be, the slow trip of a circuit breaker clearing three or more transmission lines would be reportable even if it didn’t include a Misoperations.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Tony Eddleman - Nebraska Public Power District - 3	
Answer	No
Document Name	
Comment	

In Attachment 1, the Event Type, "Transmission loss" should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type:

1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the "Generation loss" Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met.

2. Under "Transmission loss", a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant "Transmission loss" events are included in other Event Types and associated with BES Emergencies. Minor risk "Transmission loss" events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement.

3. Under "transmission loss", misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations.

4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type "Transmission loss" are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	

Comment

In Attachment 1, the Event Type, “Transmission loss” should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type:

1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the “Generation loss” Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met.

2. Under “Transmission loss”, a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant “Transmission loss” events are included in other Event Types and associated with BES Emergencies. Minor risk “Transmission loss” events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement.

3. Under “transmission loss”, misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations.

4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type “Transmission loss” are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.

Likes 0	

Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy recommends the following edits to Event Types in Attachment 1:

• Public appeal for load reduction

• Firm load shedding

We recommend the removal of the phrase “resulting from a BES Emergency” from the Event Type, and placing the phrase in the Threshold for Reporting.

Duke Energy recommends the following edits to Threshold for Reporting in Attachment 1:

• Public appeal for load reduction resulting from a BES Emergency.

• System-wide voltage reduction of 3% or more resulting from a BES Emergency.

• Firm load shedding ≥ 100 MW (manual or automatic) resulting from a BES Emergency.

We recommend the removal of the of the phrase “to maintain continuity of the BES” and replacing with the more widely understood “resulting from a BES Emergency”. We feel that adding “resulting from a BES Emergency” to the “Threshold for Reporting” in both cases consistently creates a better understanding and is less vague. By doing this, it puts the details in the “Threshold for Reporting” language where we feel they are best suited. Additionally, while we understand the phrase “to maintain continuity of the BES” would mirror the reference used in OE-417, that doesn’t mean that the phrase is any less ambiguous or clearly understood throughout the industry. With BES Emergency being a defined term, and readily used throughout the industry, we believe it better suited than the less known, undefined concept of “to maintain continuity of the BES”.

Firm load shedding resulting from a BES Emergency:

We recommend the drafting team consider adding "*or*" to the "Entity with Reporting Responsibility" section for this Event Type. We suggest the following: "*Initiating RC, BA, or TOP*". We feel that the addition of "*or*" furthers the drafting team's intent that only one of the listed entities is expected to file the report. As written, one could still read the language as to state that all entities are required to file a report rather than just the initiating entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT reviewed your comments and agreed with your suggested changes to System-wide voltage reduction and updated the Event Type category and the Threshold. The EOP SDT agrees with your comment to add 'or' between BA and TOP, it adds clarity to the Entity with Reporting Responsibility. For consistency with Attachment 1 Event Types, and identifying that a BES Emergency has occurred and that an action has taken place, no change was made to Event Type category for public appeal and firm load shedding.	
Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	
For the "Complete loss of monitoring or control capability at its staffed BES control center" Event Type, the "Threshold for Reporting" column should be revised as follows: "Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more**, such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable**." The "Threshold for Reporting" language should continue to include the "such that[…]" language to maintain consistency with the EAP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT feels that complete loss of monitoring or control capability at its staffed BES control center is clear as written and does not need "such that analysis capability (i.e., State Estimator or Contingency Analysis) added. This was discussed at length at many drafting team meetings and the "such that analysis capability (i.e., State Estimator or Contingency Analysis)" language did not bring any clarity to the reporting trigger.	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	No
Document Name	
Comment	
Regarding the Event Type "Transmission Loss" in Attachment 1, we suggest that the SDT consider one of the following options: **1. Modify the threshold language as follows:**	

"Unexpected loss within its area, contrary to design, of three or more BES Transmission elements caused by a common disturbance (excluding successful automatic reclosing)."

Reasons:

a. The current NERC Glossary of Terms definition of "Facilities" includes generators. Therefore, renewable generation such as wind farms would require reporting for the loss of three or more generators. This loss in MW is minimal compared to the threshold stated in the Event Type "Generation loss".

b. Generation loss is required to be reported by the BA. Including generation in the reporting requirements for the TOP as well introduces confusion and the possibility of unnecessary or duplicative reporting.

OR

2. Remove this event type from this section of the document.

Reasons:

a. Same reasons as listed above

b. This reporting is redundant having already been addressed in the NERC Event Analysis Program.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The previous draft revision from "Elements" to "Facilities" was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Don Schmit - Nebraska Public Power District - 5

Answer	No
Document Name	

Comment

In Attachment 1, the Event Type, “Transmission loss” should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type:

1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the “Generation loss” Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met.

2. Under “Transmission loss”, a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant “Transmission loss” events are included in other Event Types and associated with BES Emergencies. Minor risk “Transmission loss” events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement.

3. Under “transmission loss”, misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations.

4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type “Transmission loss” are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned

process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Comments: Attachment 1, Page 10, 1st Row: Event Type: **BES Emergency resulting in voltage deviation on a Facility** – The voltage deviation range, as described in "Threshold for Reporting," includes everything greater than -10% of nominal voltage which includes acceptable voltages. (e.g. For 115.0kV, everything greater than -10% would include 103.5 to 126.4kV) **Suggested Language for "Threshold for Reporting":** A voltage deviation of < -10% OR > 10% of nominal voltage sustained for > 15 continuous minutes.	
Likes 0	
Dislikes 0	
Response	
The EOP SDT appreciates you comment about the voltage reporting requirement in the Threshold for Reporting and will change the language to "A voltage deviation of =/> 10% of nominal voltage sustained for > 15 continuous minutes."	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At times there may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend replacing "BA" with "Initiating BA or TOP." The event types with multiple applicable entities such as, "Uncontrolled loss of firm load resulting from a BES Emergency", and "System separation (islanding)" will most likely have the same event reported multiple times if the BA, TOP or RC are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type, "Uncontrolled loss of firm load resulting from a BES Emergency" to just the BA. We recommend changing the Entity with Reporting Responsibility for the Event Type, "System separation (islanding)" to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Reliability Standard EOP-011-1 (subject to future enforcement) puts the responsibility of having Public Appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004.

If an event applies to any of the entities listed as the "entities with reporting responsibilities," then it is up to those entities to ensure reporting is done. Whether it be reporting the event themselves or delegating reporting responsibilities, this should all be covered in the entity's event reporting Operating Plan.

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	

It appears that Attachment 1 is an effort to consolidate two separate reporting requirements. PJM believes the revision adds a bit of confusion. The 'Automatic' reporting section today states: via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS. PJM believes that the Standard should incorporate this clarity in the new EOP requirement so there is no confusion about reporting of 'automatic' load shed between 100-300MWs due to loss of BES Facilities (i.e. storms) which could be considered an emergency and also automatic, uncontrolled loss of 300MWs for any reason is reportable, which is why the 100-300MW presents confusion.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The EOP SDT feels that the Threshold for Reporting is clear, the Responsible Reporting Entity will know if the Firm load shedding was done either manually, automatically or a combination of both.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	

Under physical threats to a facility, suspicious activity at a facility must be defined. I suggest suspicious activity be given its own row (removed from within physical threats to a facility). Specifically, "suspicious device or activity" is ambiguous. Further clarification on "suspicious activity" is needed. For example, does this include photography near a Facility? Also, Attachment 1 should specifically cover cyber related suspicious activity – for example, solicitation attempts or phishing calls at Facilities. There should also be instruction on what an Entity should do if they later realize the incident was NOT suspicious – for example, a prior reported incident which, after further investigation, turns out to be innocuous. The effect of using ambiguous terms and no mechanism for correcting incidents post investigation has left the industry with an output that contains more "trash" than value – many incidents that do not truly meet the definition of EOP 004 are sent out via EISAC which leads to the dilution of truly important incidents.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The EOP SDT feels the language in the Threshold for Reporting is clear as written. This is the language in the original reporting requirement the only change the EOP SDT made was the removal of “Do not report theft unless it degrades normal operation of a Facility.” Entities should define in their event reporting Operating Plan what they deem as suspicious, and report accordingly.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

(1) We believe the SDT is attempting to align Transmission Loss events with similar reportable criteria listed under the current NERC Event Analysis process. As identified within supportive documentation for this mature process, Category 1a Events caused by common disturbances affecting BES Facilities only refers to BES-defined lines, generators, and transformers. When capitalizing Facility in the context of this reportable criterion, this includes equipment like shunt compensators, circuit breakers, and busses. Furthermore, events caused by Misoperations are reportable under NERC Reliability Standard PRC-004, and could cause repetitive reporting in the process. If the SDT does not consider the outright removal of this event type from the EOP-004 reportable criteria, we recommend rephrasing the threshold for reporting a Transmission Loss event, as reportable to TOPs only, as “Unexpected loss, within its area and contrary to design or successful automatic reclosing, of three or more Transmission Facilities caused by a common disturbance.”

(2) The reference to “=/>” in the reporting threshold for a BES Emergency resulting in a voltage deviation literally reads “equal to or greater than.” Is the intent of the SDT to identify a reporting threshold greater than ± 10% of nominal voltage? We propose using the symbol “≥” to reflect reporting a sustainable voltage deviation that is greater than or equal to ± 10% of nominal voltage over a continuous 15-minute period.

(3) We believe the proposed reportable threshold reference under Generation Loss should be clarified to identify Forced Outages only. Forced Outages is listed under the NERC Glossary and identifies the removal of generation from service for either emergency reasons or unanticipated failures. We feel the incorporation of references to extreme weather patterns or fuel supply unavailability is unnecessary when used within this context.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP.

The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

The EOP SDT appreciates you comment about the voltage reporting requirement in the Threshold for Reporting and will change the language to “A voltage deviation of =/> 10% of nominal voltage sustained for > 15 continuous minutes.”

The EOP SDT discussed your comment and decided no changes were needed to the Generation loss Event Type category.

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Overall the changes to the Standard are positive and WAPA appreciates the efforts of the SDT. However, there is still significant room for confusion regarding reportable Transmission Loss Events as a TOP with the change from Element to Facility. WAPA would very much appreciate examples within the standard that clarify events which would be reportable and events which would not be reportable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The previous draft revision from "Elements" to "Facilities" was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy generally agrees with the SDT's proposed revisions to EOP-004-3, Attachment 1: Reportable Events, but would like the SDT to consider the following: The addition of the word "staffed" in front of "BES control center…" becomes a qualifier to distinguish which control center is in scope for reporting to this category. An entity may have more than one control center that is "staffed" but we believe that the control center that is responsible for performing Real-time functions responsible for reliability is the control center that is in scope for when the threshold for complete loss of interpersonal Communication capability has been lost is met. Additionally, the term "control center" is not capitalized. We suggest that the term be capitalized to align with the glossary definition of Control Center and to align with the use Control Center in category 1h as it applies to the loss of monitoring or control at a Control Center. It is not necessary to have BES in front of Control Center because it is already included in the NERC definition. In summary, CenterPoint energy offers the following suggestions for the Event Type and Threshold for Reporting: Event Type - Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a Control Center. Threshold for Reporting - Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting a staffed Control Center responsible for performing Real-time functions for the reliability of its BES for 30 continuous minutes or more.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The EOP SDT team reviewed your comment about removing "its staffed" related to monitoring or control and Interpersonal/Alternative Interpersonal Communications. The team held many discussion on this topic related to staffed or not staffed; and, yes, it is important to the capability there, but if the site is not staffed the responsible entity will not be aware of the issue plus if you are not actively operating from the site there is no impact on reliability. The team is sure once the issues are identified the responsible entity will resolve the situation. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The NSRF believes we discovered a compliance concern that may cause entities to be non-compliant with Attachment 1, Event Type of *Transmission loss*. With the use of Facility (and Element) in threshold for reporting, a Transmission Operator may not be aware that the NERC defined term of Facility also contains "a generator". Even though Event Type *Generation loss* is predicated on a MW threshold, a *Transmission loss* event also contains generators. So, a TOP may lose 2 BES Transmission Facilities AND a BES Generator is tripped (due to the same Event), the TOP has then met the loss of "three or more BES Facilities" and is required to make a report per EOP-004-4. Either the SDT or NERC should publically post this clarification so all TOPs understand their obligations to the current enforceable EOP-004-2 and any further enforceable EOP-004. BES Elements (lines, transformers, and I5 reactors) that operate as a single Facility should be counted as one Facility. This is predicated on the definition that a Facility is "a set of…".	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The previous draft revision from "Elements" to "Facilities" was to align with the EAP. Some examples of Transmission loss can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

Draft Standard EOP-004-4 Attachment 1, under table heading “Event Type”, Reclamation respectfully suggests consistent application of the replacement of “a” with “its” when referencing the Responsible Entity’s ownership, to be consistent with EOP-004-4 Attachment 2’s use of “its”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under damage or destruction of “a” Facility, the Event Type is deliberately listed as “a” Facility because the intent is to report on “all” Facilities in its RC/BA/TOP area.	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - Andrew Pusztai	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	
I suggest suspicious activity be given its own row.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT finds that suspicious activity within Event Types: "Physical threats to its Facility and Physical threats to its BES control center" are clear as written in the Threshold for Reporting and does not require its own row.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Please see Texas RE's comment for #2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Question 2.	
Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the language should only refer to required event reporting to Operating Plan entities (e.g. NERC and/or DOE) within the reporting period.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The EOP SDT finds that the Responsible Entity can define who the entities they report are within their event reporting Operating Plan.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation suggests consistent application of the replacement of “a” with “its” as it pertains to the Responsible Entity’s ownership.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under damage or destruction of “a” Facility, the Event Type is deliberately listed as “a” Facility because the intent is to report on “all” Facilities in its RC/BA/TOP area.	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Depending on the changes (if any) made to the recommendations stated in Question 2 above for Event Type "Transmission loss", Attachment 2 will need to be revised accordingly.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy suggests that the “Tasks” in Attachment 2 Event Reporting Form align with the Event Types in Attachment 1 if revised by the SDT.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Attachment 2 has been updated.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	Proposed_EOP-004-4_Attachment2.docx
Comment	
We find the proposed two-page format of the Attachment 2 form impractical. We offer a single page solution, as an attachment and proof that this information can be condensed accordingly.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Formatting has been changed to reduce Attachment 2 to a one-page document.	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - Andrew Pusztai	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) Based on the specifics of Attachment 1, we believe there is sufficient information available to include an applicability section within the standard pertaining to Facilities. The intent of this standard is to not capture events occurring on non-BES identified facilities. This would include reporting on small generating resources or dispersed power producing resources with nameplate ratings under 20 MVA or aggregate nameplate ratings under 75 MVA that are connected to a common connection point at 100 kV or above. (2) We question the VSL for Requirement R2 identifying a severity for when a Responsible Entity fails to submit an event report within 24 hours. We ask the SDT to clarify if the severity is based on 24 hours of the event's discovery or within 24 hours of the event's conclusion, independently of the expectation already proposed within the requirement text. (3) From the last commenting period for this draft standard revision, we previously recommended the implementation of an event reporting software tool on the NERC website providing capabilities to notify applicable Regional Entities and the DOE. We thank the SDT for its efforts to align event reporting activities with the DOE. However, based on the SDT's response to our comments, we are left with the impression that no automated mechanism is available to share event notifications submitted to the DOE with required Regional Entities, Reliability Coordinators, law enforcement, and other governmental authorities per Requirement R1. We believe a preventable human performance issue could be diverted through the development of a centralized portal that would disperse event reports to appropriate entities when necessary. We again ask the NERC Standards Developer assigned to this project to share this comment with NERC's IT department to see if a viable solution is available or could be developed. (4) We thank you for this opportunity to provide feedback.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Attachment 1, as it relates to Facilities, is clear as written. A Facility is defined in the NERC Glossary as; “A set of electrical equipment that operates as a single BES Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” The EOP SDT has updated the VSLs for Requirement R2. NERC Events Analysis has been forwarded your comment regarding implementation of an event reporting software.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	
Document Name	

Comment

R2 of EOP-004-4 state:

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan:

-by the later of 24 hours of recognition of meeting an event type threshold for reporting

or

-by the end of the Responsible Entity’s next business day (4 p.m. local time will be considered the end of the business day).

The VSL Section state:

The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting.

By example, if an event occurred at midnight (12 a.m. Tuesday), the entity can submit a report by the end of the next business day (4 p.m. local time will be considered the end of the business day) which is Wednesday 4p.m. That means 40 hours after the event.

We suggest to remove this paragraph “The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR” of the Lower VSL.

We suggest also modifying the moderate VSL as following: “The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 40 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting.”

1. In the section below, not sure why “Event Report” is capitalized? It seems that this “NOTE” intends to give an entity flexibility on the reporting timing, “under certain adverse conditions”, by differentiating between issuing a “written Event Report” and a “notification” (still to be done within timing requirements of R2), but I’m not sure this is the reasons for capitalizing “Event Report”?

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1

2. For SDT's consideration - Event Types in the Attachment 1 do not seem to capture GOP BES control centers (either evacuation or physical threats)?

· By capitalizing "Facility" in the Event Type for a "Physical Threat to its Facility", since this term is defined in the NERC Glossary (and does not capture control center in the definition), this category excludes GOPs from reporting physical threats to their BES control centers under EOP-004.

· By excluding GOPs from the "Entity with Reporting Responsibility" list in the "Unplanned BES control center evacuation" Event Type, this category excludes GOPs from reporting evacuations from their BES control centers under EOP-004.

· Same as the bullet above for the "Complete loss of Interpersonal Communication capability at a BES control center"

Not sure if this is an intentional omission? CIP standards explicitly identify GOP control centers (High, Medium and Low Impact Rating) as subject to CIP requirements. CIP requirements are being implemented recognizing that there is an impact on BES from a CIP incident on a GOP control center, but EOP-004 doesn't capture non-cyber events associated with the same facilities for reporting requirements – seems inconsistent.

At least High Impact GOP control centers, under the "Threshold for Reporting" should be considered for reporting requirements under EOP-004, for the events identified above.

This comment is being submitted recognizing that the current version of EOP-004-2 does not required this reporting either, for the same reasons identified in the three bullets above.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The EOP SDT updated the VSLs for Requirement R2. The first paragraph of EOP-004, Attachment 1, has been updated.

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers. In addition, there is no specific requirement in CIP-006 to report any physical threats to a Facility. CIP-006 says to refer to CIP-008 Cyber Security response plan. The Cyber Security response plan requires notification to E-SIAC only, which is not related to EOP-004 reporting.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

In its previous comments, Texas RE requested that the SDT provide the rationale for adopting a 12-month implementation timeframe. In particular, Texas RE noted that "Given that registered entities presently are required to submit event reports under the current version of EOP-004 and the revised version largely narrows the scope of such reporting activities, it is unclear why a 12-month implementation period is necessary." With this comment, Texas RE sought to understand the basis for the SDT's conclusion that a 12-month period was necessary to give entities appropriate time to address the revised Standard requirements. Rather than provide a rationale in its response, the SDT merely noted that its intent is for the 12-month Implementation Plan "was to give all entities an appropriate time frame for implementation."

Texas RE therefore reiterates its request that the SDT provide a substantive basis for its determination that a 12-month time frame is appropriate. In response, the SDT could describe the additional compliance obligations for entities for the revisions, whether these will impose additional costs, require additional staffing, or other compliance burdens that serve as the basis for its conclusion.

Likes 0	
Dislikes 0	

Response

The Implementation Plan takes into account any barriers to implementation. The EOP SDT intent for the twelve-month Implementation Plan was to give all entities an appropriate time frame for implementation. Based on the EOP SDT's expertise, there are multiple processes that a NERC standard procedure has to go through and evaluated by an entity prior to being finalized, trained on, and approved. This standard would require changes to processes/procedures and training shift workers which requires ample time; and, therefore, a 12-month Implementation Plan is required.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

We suggest capitalizing the term **"control center"** as it's defined in the NERC Glossary of Terms. Additionally, the terms "Reliability Coordinator (RC)", "Balancing Authority (BA)", and "Transmission Operator (TOP)" (applicable in the **Entity with Reporting Responsibility sections of Attachment 1)** are terms included in the definition of the term **"Control Center"** which provides more details on why the term should be capitalized throughout Attachment 1.

Likes 0	
Dislikes 0	

Response

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.

Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay

Answer	
Document Name	

Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
R2 of EOP-004-4 state: Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan: -by the later of 24 hours of recognition of meeting an event type threshold for reporting or -by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). The VSL Section state: The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting.	

Based on this example, if an event occurred at midnight (12 a.m. Tuesday), the entity can submit a report by the end of the next business day (4 p.m. local time will be considered the end of the business day) which is Wednesday 4p.m. That means **40** hours after the event. On the Lower VSL, Hydro-Quebec TransEnergie suggest to remove this paragraph "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR" . On the Moderate VSL, Hydro-Quebec TransEnergie suggest modifying as following: "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 40 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT updated the VSLs for Requirement R2.	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	
Document Name	
Comment	
The VSLs for R2 need to reflect the change in reporting deadlines to accommodate the reporting entity's next business day	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the VSLs for Requirement R2.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
"Suspicious device or activity" in Attachment 1 is not defined even though Suspicious is capitalized. The NERC Glossary of Terms does not define "Suspicious" either.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. "Suspicious" is capitalized because it is the first word in a new sentence. It was not the intent of the EOP SDT for "suspicious" to be defined.	

Consideration of Comments

Project Name:	2015-08 Emergency Operations | EOP-004-4
Comment Period Start Date:	11/18/2016
Comment Period End Date:	1/9/2017
Associated Ballots:	2015-08 Emergency Operations | EOP-004-4 EOP-004-4 AB 2 ST

There were 38 sets of responses, including comments from approximately 33 different people from approximately 31 companies representing 8 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

2. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Bill Watson	Old Dominion Electric Cooperative	3,4	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Matt Caves	Western Farmers Electric Cooperative	1,5	SPP RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC

Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

David Ramkalawan	Ontario Power Generation	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	UI	3	NPCC
Michele Tondalo	UI	1	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Si Truc Phan	Hydro Quebec	2	NPCC
Helen Lainis	IESO	2	NPCC

					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO

Midwest Reliability Organization					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO

					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Colorado Springs Utilities	Shannon Fair	6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE

				Review Group	James Nail	Independence Power and Light	3	SPP RE
					Tara Lightner	Sunflower Electric	1	SPP RE
					Robert Gray	Board of Public Utilities (BPU) Kansas City, KS	3	SPP RE
					Leo Bernier	AES	NA - Not Applicable	NA - Not Applicable
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Sean Simpson	Board of Public Utilities, Kansas City, KS	3	SPP RE
					Tony Eddlement	Nebraska Public Power District	1,3,5	SPP RE

1. Do you agree with the SDT's recommended changes to EOP-004-3, Requirements R1 and R2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests clarification on the addition of "by the later of" and the use of 4pm as the end of a business day. Is it the drafting team's intent that the Responsible Entity has the option of submitting an Event Report 24 hours after the Event threshold has been reached, or the entity may choose to submit the report later than the 24 hours, as long as the report is submitted by 4pm the next business day? The proposed language as currently written may create some ambiguity depending on the reader.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
As stated in the comments with the initial ballot, Texas RE noticed there is no requirement specifically indicating how events should be reported. Additionally, the VSLs indicate that a verbal report is acceptable. Since an event reporting form exists, Texas RE recommends the requirements specify the form in Attachment 2 be used for event reporting.	

In the Severe VSL for R2 "-4_ should be added to the last sentence to maintain consistency (e.g. "EOP-004-4").

Likes 0	
Dislikes 0	

Response
Thank you for your comment. **"Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2"** is stated in Attachment 1 of the standard. The VSL for Requirement R2 has been updated: "The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1."

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment
(1) We thank the SDT for the development of this draft standard revision and the removal of the administrative burden reflected in Requirement R3 of the current standard. While we generally agree with the results-based compliance approach presented in this draft, we feel that the SDT has an opportunity to further clarify the intentions of their proposed changes. (2) We believe Requirement R2 is intended to provide the Responsible Entity an option of using the criterion that will occur last when reporting. While either criterion will occur "later" from the initial event discovery, as used in the context of an adverb describing a point in time, the ability to select one criterion versus the other is an adjective that describes the criteria's comparison. We recommend using "…by the latter of…" in the requirement text instead. (3) The first criterion listed in Requirement R2 states "24 hours of recognition of meeting an event type threshold for reporting." We believe the SDT inadvertently removed a necessary and supportive phrase that identifies the duration of the criterion. We also believe the SDT failed to establish a starting trigger for this criterion with the recognition and discovery of the event. We recommend rewording the criterion to read "within 24 hours following recognition of meeting an event type threshold for reporting." (4) The second criterion listed in Requirement R2 identifies the end of a business day as 4:00 PM. What is the rationale for selecting an arbitrary time? How do joint-filing entities that operate across large geographic regions and multiple time zones identify the local

time? How does a single entity with centralized operations in one time zone identify local time for an event originating in a different time zone? We agree with the SDT's intent to remove ambiguity regarding weekends and holidays, but believe the addition of the 4:00 PM local time reference creates unintended confusion. We recommend removing the reference entirely and allow some flexibility for the Responsible Entity to define its own meaning of "next business day." This would allow smaller entities, with a limited impact on BES reliability, to report after an extended weekend and after becoming fully staffed. (5) To clearly delineate the possible criteria available for Requirement R2, we believe each criterion should be renumbered into individual subparts list.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day (4:00 pm was selected because it is a typical ending time for operating personnel). The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of the next business day based on the local time of the entity's centralized location. The Responsible Entity could document this in their event reporting Operating Plan.	
Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the R2 language should only refer to required event reporting to Operating Plan entities (e.g. NERC and/or DOE) within the reporting period.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The EOP SDT finds that the Responsible Entity can define who the entities they report are within their event reporting Operating Plan.	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
The VSLs for R2 need to reflect the change in reporting deadlines to accommodate the reporting entity's next business day	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the VSLs for Requirement R2.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
To clarify the Standard pertains to Event Reporting, Reclamation respectfully proposes the following revised language for Standard EOP-004-4, R1, R2, M1, and M2: R1. : Each Responsible Entity shall have an Event Reporting Operating Plan that includes the protocol(s) for reporting the Reportable Events listed in EOP-004-4 Attachment 1 to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, Responsible Entity personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority).	

Reclamation suggests re-wording M1 as follows: Each Responsible Entity will have a dated Event Reporting Operating Plan that includes the reporting protocol(s) and name(s) of organization(s) to receive an event report for the Reportable Event(s) specified in EOP-004-4 Attachment 1. R2. Each Responsible Entity shall report the types of events specified in EOP-004-4 Attachment 1, to the entities specified per its Event Reporting Operating Plan, by the later of 24 hours after recognition of meeting an event type threshold or by the end of the Responsible Entity's next business day, whichever is later (4 p.m. local time will be considered the end of the business day). M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within the timeframes identified in R2 above. Reclamation suggests the following change to both R2 and M2: "by the later of 24 hours after recognition of meeting an event type…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT finds the language in Requirement R1 and Measure M1 is clear as written and it does not require the specifics you are asking for in your suggested language. Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day. The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of the next business day based on the local time of the entity's centralized location. The Responsible Entity could document this in their event reporting Operating Plan.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
The NSRF would like to thank the Standard Drafting Team (SDT) for their thoughtful changes and believes the revisions proposed are valuable. Please see question two for concerns that we have.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to Question 2.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
With regard to requirement R2, AZPS recommends modifying the text for clarity to read as “the later of 24 hours following recognition of meeting an event type” as opposed to “the later of 24 hours of recognition of meeting an event type.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to provide entities at least 24 hours for reporting after recognition of an event; for recognition of reporting events on a weekend or a holiday, it allows the entity up to 4:00 p.m. on their next business day. The recognition of meeting an event type would be the trigger for reporting. It is the intent of the drafting team that the Responsible Entity would report by 4 p.m. of the next business day based on the local time of the entity’s centralized location. The Responsible Entity could document this in their event reporting Operating Plan.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
As for Requirement R1, we have no concerns pertaining to the proposed changes. However, we feel the clarity notes applicable to Measurement M1 in the comment form are inaccurate (page 2). The notes mentions the correction to the version number however, it doesn't mention the phrase **"but is not limited to the"** being stricken from the standard. We suggest the drafting team update all applicable documents to reflect that change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the Mapping Document.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
WAPA appreciates the efforts of the Standards Drafting Team (SDT) and welcomes the changes.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - Andrew Pusztai	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the proposed revisions to EOP-004-3, Attachment 1? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	ERO_EAP_Documents DL-Justification_for_Event_Category_1g_and_3a_changes_for_ERCOT.pdf
Comment	

ERCOT appreciates the SDT revising the generation loss reporting threshold for the ERCOT Interconnection to 1,400 MW from 1,000 MW in Attachment 1 of EOP-004. This change is consistent with ERCOT's September 8, 2016 comments, which requested this revision to align the reporting threshold with the *ERO Event Analysis Process* (EAP) document's threshold for initiating an analysis of a Category 3a generation loss event in the ERCOT Interconnection, which, at the time of ERCOT's comment, was 1,400 MW.

However, concurrent with Project 2015-08, the NERC Event Analysis Subcommittee (EAS) proposed changes to the EAP document that, among other things, sought to standardize the event analysis threshold for all Interconnections—including ERCOT—at 2,000 MW. The draft EAP document was first posted for comment on the NERC website on September 30, 2016, some three weeks after ERCOT submitted its comments to the latest version of EOP-004. The revised EAP document—version 3.1—was ultimately approved by the NERC Operating Committee at its December 13, 2016 meeting and became effective January 1, 2017. Thus, the threshold for conducting an analysis of Category 3a events is now 2,000 MW.

Consistent with ERCOT's September 8 comments and with the SDT's change to the reporting threshold in the last version of the draft standard, ERCOT believes the threshold for generation loss reporting in EOP-004 should continue to align with the EAP document's threshold for analysis of Category 3a events, which is now 2,000 MW. If there are any reasons for differentiating between the two thresholds, this justification does not seem immediately obvious. Fundamentally, in ERCOT's view, it would make little sense to require development of a written report of a generation loss event and distribute it to various entities if the event did not also justify an analysis under the EAP process. Furthermore, the reasons cited by the EAS for increasing the event analysis threshold—the implementation of BAL-003-1.1 and BAL-001-TRE-01, and the procurement of greater quantities of responsive reserve in ERCOT, among other reasons—would also appear to justify increasing the event reporting threshold. See *Justification for Proposed Changes to the ERO Event Analysis Process Categories 1g and 3a* (attached).

In conclusion, ERCOT appreciates the SDT's recognition of the need to align the EOP-004 generation loss reporting threshold with the EAP document's generation loss event analysis threshold and asks the SDT to continue this alignment by setting the generation loss reporting threshold for the ERCOT Interconnection in EOP-004 Attachment 1 to 2,000 MW.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. To establish the equitable criteria for reporting in the ERCOT interconnection, the EOP SDT has revised the reporting threshold from 1,000 MW to 1,400 MW for generation loss in the ERCOT interconnection, as recommended from the September comments. Please refer to the project's mapping document for the technical justification regarding this revision. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The reporting threshold for generation loss in the ERCOT Interconnection in proposed EOP-004-4 is aligned with the DOE OE-417.	
Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the BA or TOP could be the initiating parties for a load appeal. Also, more clarity should be added for automatic load shedding causes (UVLS, UFLS, RAS).	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. EOP-011-1 puts the responsibility of having public appeals for load reduction in the BA's Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. The EOP SDT feels that the Threshold for Reporting is clear, the Responsible Reporting Entity will know if the Firm load shedding was done either manually, automatically or a combination of both.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
For the "Complete loss of monitoring or control capability at its staffed BES control center" Event Type, the "Threshold for Reporting" column should be revised as follows: "Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more, such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable." The "Threshold for Reporting" language should continue to include the "such that […]" language to maintain consistency with the EAP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has discussed your comment but finds that the Event Type and Threshold for Reporting are clear as written.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE appreciates the SDT's response to Texas RE's previous comments regarding the removal of the IROLTV reporting obligation. As the SDT noted in its response, the SDT removed the reporting requirement because the new TOP-001-3 R12 requirement requires registered entities to avoid exceeding IROLs for the relevant TV period. As such, the SDT reasons that entities will self-report any noncompliance and there is no need to retain the corresponding reporting requirement.

Texas RE sees two issues with the SDT's rationale. First, as Texas RE noted in its original comments, there is a significant difference in the purpose and timing of the EOP-004 reporting requirements and the substantive obligations set forth under the new TOP-001-3, R12. Texas RE noted: "While such an exceedance may be investigated in the compliance or enforcement process, there is necessarily a delay in these activities. The contemporaneous reporting obligations serve to ensure that the NERC regions have immediate knowledge that a significant risk of a cascading outage has occurred, permitting the region to begin steps to identify the root cause and develop appropriate mitigation. Because such awareness appears critical to the core reliability functions performed within the NERC regions, Texas RE cautions against eliminating this requirement." Simply put, the mere existence of a parallel substantive requirement does not address Texas RE's concern. Texas RE cannot support the elimination of the IROLTV reporting obligation based on the SDT's proffered rationale.

Second, the SDT appears to misunderstand the self-reporting process. Principally, entities are under no obligation to self-report potential noncompliance instances, and may elect not to do so at their sole discretion. Given that certain utilities are on three- or even six-year audit cycles, an entity could decline to self-report an IROL exceedance violating TOP-001-3, R12 and wait until its next scheduled audit (contingent on the requirement being included in the audit scope). Accordingly, a potential issue could linger for years before it is addressed in the enforcement process. This is precisely the reason Texas RE believes the contemporaneous reporting requirement continues to be a necessary part of the NERC Reliability Standards.

Texas RE also suggests the Standard is too narrow in its reporting requirements for events. According to the Events Analysis Process effective January 1, 2017, "The primary reason for participating in an event analysis is to determine if there are lessons to be learned and shared with the industry. The analysis process involves identifying what happened, why it happened, and what can be done to prevent reoccurrence." Texas RE recommends broadening the requirements in order to understand prevention as well as what took place when event actually occurred. Texas RE provides the following suggestions for broadening the reporting requirements.

- Public appeal for load reduction should not be limited to a BES Emergency. In some cases the appeal may be done to avoid a BES Emergency and that event should be evaluated per the Events Analysis Process in order to prevent issues from occurring in the future.

- As previously submitted in comments with the initial ballot, Texas RE recommends adding the TOP function to the public appeal event type. This will align and be consistent with EOP-001-2.1b Requirement R2, which requires a TOP to “Develop, maintain, and implement a set of plans for load shedding”, EOP-001-2.1b Requirement R3, which requires a TOP emergency plan to include “Load reduction”, and EOP-001-2.1b Requirement R4, which references elements in Attachment 1-EOP-001 that a TOP and BA should consider when developing emergency plans.

- For the event types, “Complete loss of monitoring or control capability at its staffed BES control center” and “Complete loss of Interpersonal Communications and Alternative Interpersonal Communication capability at its staffed BES control center”, Texas RE recommends removing “its staffed”. Loss of monitoring or control capability is just as important at a non-staffed site as it is a staffed site and there should be no distinction in staffing status. Understanding why complete loss of monitoring or control capability and complete loss of Interpersonal and Alternative Interpersonal Communications occurred will increase the likelihood of prevention in the future.

Reliability Standard EOP-004-2 does not take into account GOP Control Centers. As previously stated, Texas RE recommends adding the GOP to the entity with reporting responsibility. Reliability Standard CIP-002-5 states that “each Control Center or back up Control Center used to perform the functional obligations of the Generator Operator” (CIP-002-5, Attachment 1, Sections 1.4 and 2.11) should be considered in an entity’s identification of high and medium BES Cyber Systems. Reliability Standard CIP-008-5 Requirement 1 requires Responsible Entities with High and Medium Impact BES Cyber Systems (which could include GOP Control Centers) to have a process to determine if a Cyber Security Incident is reportable and noticed the E-ISAC. Since this includes GOP Controls Centers, it would be consistent to include GOP Control Centers in EOP-004-4. Also, there are several GOPs in Texas (and other regions) that may control more megawatts than some BAs and yet there is no requirement to report events that occur so they are studied and preventative measures are taken in the future. Since CIP-002-5 has a mechanism for considering GOP Control Centers, and there are several GOP Control Centers that may control as much or more generation than a BA, Texas RE recommends adding the GOP as an entity with reporting responsibility. From a consistency and reliability stand point, events that occur at a GOP Control Center should be reported on and evaluated.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The EOP SDT has discussed your concerns and still contends that IROL reporting should be removed from this standard. TOP-001-3, Requirement R12 becomes effective 4/1/17, requiring a self-report if Tv is exceeded; TOP-007-WECC-1 is pending retirement; IRO-009-2, Requirement R3, requires the RC to act or direct others to act until the IROL exceedance is mitigated with in the IROL's Tv. The EAP also lists Category 2 "…g.) Interconnection Reliability Operating Limit (IROL) Violation for the time greater than Tv." EOP-004 is not the proper vehicle for immediate reporting. The drafting team suggests following the standard development process of submitting a SAR for modification.

The purpose of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary, data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417.

Public appeal for load reduction in a BES Emergency is in the currently-enforced EOP-004 standard, the EOP SDT finds the Event Type is appropriate as written.

In Reliability Standard EOP-011-1 (subject to future enforcement, retires EOP-001-2.1b, EOP-002-3.1, and EOP-003-2), Requirement R2, it is the function of the BA to include within its RC-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies public appeals for voluntary load reductions (Requirement R2, Part 2.2.4.). The BA is the proper Entity with reporting responsibility for public appeal for load reduction resulting in a BES Emergency.

The EOP SDT team reviewed your comment about removing "its staffed" related to monitoring or control and Interpersonal/Alternative Interpersonal Communications. The team held many discussion on this topic related to staffed or not staffed; and, yes, it is important to the capability there, but if the site is not staffed the responsible entity will not be aware of the issue plus if you are not actively operating from the site there is no impact on reliability. The team is sure once the issues are identified the Responsible Entity will resolve the situation.

The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event

reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We suggest that the Event Type **"Transmission Loss"** in Attachment 1 be removed from this section of the document. We feel that this effort is redundant and has been addressed in the NERC Event Analysis Program. Our first example would be applicable to, the renewable generation such as wind farms would require reporting for the loss of three or more generators pertain to a Misoperations. Another example would be, the slow trip of a circuit breaker clearing three or more transmission lines would be reportable even if it didn't include a Misoperations.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The previous draft revision from "Elements" to "Facilities" was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.	

Tony Eddleman - Nebraska Public Power District - 3	
Answer	No
Document Name	
Comment	

In Attachment 1, the Event Type, “Transmission loss” should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type:

1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the “Generation loss” Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met.

2. Under “Transmission loss”, a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant “Transmission loss” events are included in other Event Types and associated with BES Emergencies. Minor risk “Transmission loss” events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement.

3. Under “transmission loss”, misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations.

4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type “Transmission loss” are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
In Attachment 1, the Event Type, “Transmission loss” should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk	

Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type: 1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the “Generation loss” Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met. 2. Under “Transmission loss”, a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant “Transmission loss” events are included in other Event Types and associated with BES Emergencies. Minor risk “Transmission loss” events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement. 3. Under “transmission loss”, misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations. 4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type “Transmission loss” are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends the following edits to Event Types in Attachment 1: • Public appeal for load reduction • Firm load shedding We recommend the removal of the phrase “resulting from a BES Emergency” from the Event Type, and placing the phrase in the Threshold for Reporting. Duke Energy recommends the following edits to Threshold for Reporting in Attachment 1: • Public appeal for load reduction resulting from a BES Emergency. • System-wide voltage reduction of 3% or more resulting from a BES Emergency. • Firm load shedding ≥ 100 MW (manual or automatic) resulting from a BES Emergency. We recommend the removal of the of the phrase “to maintain continuity of the BES” and replacing with the more widely understood “resulting from a BES Emergency”. We feel that adding “resulting from a BES Emergency” to the “Threshold for Reporting” in both cases consistently creates a better understanding and is less vague. By doing this, it puts the details in the “Threshold for Reporting” language	

where we feel they are best suited. Additionally, while we understand the phrase "to maintain continuity of the BES" would mirror the reference used in OE-417, that doesn't mean that the phrase is any less ambiguous or clearly understood throughout the industry. With BES Emergency being a defined term, and readily used throughout the industry, we believe it better suited than the less known, undefined concept of "to maintain continuity of the BES". Firm load shedding resulting from a BES Emergency: We recommend the drafting team consider adding "*or*" to the "Entity with Reporting Responsibility" section for this Event Type. We suggest the following: "*Initiating RC, BA, or TOP*". We feel that the addition of "*or*" furthers the drafting team's intent that only one of the listed entities is expected to file the report. As written, one could still read the language as to state that all entities are required to file a report rather than just the initiating entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT reviewed your comments and agreed with your suggested changes to System-wide voltage reduction and updated the Event Type category and the Threshold. The EOP SDT agrees with your comment to add 'or' between BA and TOP, it adds clarity to the Entity with Reporting Responsibility. For consistency with Attachment 1 Event Types, and identifying that a BES Emergency has occurred and that an action has taken place, no change was made to Event Type category for public appeal and firm load shedding.	
Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	
For the "Complete loss of monitoring or control capability at its staffed BES control center" Event Type, the "Threshold for Reporting" column should be revised as follows: "Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more**, such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable**." The "Threshold for Reporting" language should continue to include the "such that[…]" language to maintain consistency with the EAP.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT feels that complete loss of monitoring or control capability at its staffed BES control center is clear as written and does not need “such that analysis capability (i.e., State Estimator or Contingency Analysis) added. This was discussed at length at many drafting team meetings and the “such that analysis capability (i.e., State Estimator or Contingency Analysis)” language did not bring any clarity to the reporting trigger.	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	No
Document Name	
Comment	

Regarding the Event Type “Transmission Loss” in Attachment 1, we suggest that the SDT consider one of the following options:

1. Modify the threshold language as follows:

“Unexpected loss within its area, contrary to design, of three or more BES Transmission elements caused by a common disturbance (excluding successful automatic reclosing).”

Reasons:

a. The current NERC Glossary of Terms definition of “Facilities” includes generators. Therefore, renewable generation such as wind farms would require reporting for the loss of three or more generators. This loss in MW is minimal compared to the threshold stated in the Event Type “Generation loss”.

b. Generation loss is required to be reported by the BA. Including generation in the reporting requirements for the TOP as well introduces confusion and the possibility of unnecessary or duplicative reporting.

OR

2. Remove this event type from this section of the document.

Reasons:

a. Same reasons as listed above b. This reporting is redundant having already been addressed in the NERC Event Analysis Program.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The previous draft revision from "Elements" to "Facilities" was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
In Attachment 1, the Event Type, "Transmission loss" should be eliminated from mandatory reporting. Events reported under this category are included in voluntary reporting under the NERC Event Analysis Program and this minimum impact level of events should not be included in mandatory compliance reporting subject to fines and penalties. This category includes BES Facilities experiencing unexpected loss, contrary to design, of three or more BES Facilities. Facilities are defined as: A set of electrical equipment that operates as a single Bulk	

Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The following examples support removal of this Event Type: 1. Renewable generation, such as wind farms, with total generation >75MWs are included in BES Facilities. A misoperation on a feeder at a wind facility including three (3) or more generators would require a mandatory report under EOP-004-4. A typical wind farm generator is approximately 1.5 – 3.0 MWs each. So, under Transmission loss, a generation loss of less than 10 MWs is required to be reported, but under the "Generation loss" Event Type in Attachment 1 to EOP-004-4, the reportable generation loss would need to be greater than 2,000 MWs (Eastern Interconnection) to be subject to mandatory fines and penalties. 10 MWs versus 2,000 MWs is an obvious disparity and clearly shows the minimal level of impact to reliability of the BES is not met. 2. Under "Transmission loss", a slow trip of a circuit breaker clearing a bus with 3 or more transmission lines or transformers, or generators, would be reportable under this mandatory compliance obligation and subject to fines and penalties. This can happen even without a misoperation, if the circuit breaker is merely slow in clearing the fault and the backup protection on the breaker clears the bus. All the protection systems can operate correctly and an entity is still subject to reporting under this event type. These types of events are being collected under the NERC Event Analysis Program and these events do not meet the threshold of risk to the BES to enforce fines and penalties. More significant "Transmission loss" events are included in other Event Types and associated with BES Emergencies. Minor risk "Transmission loss" events are more appropriately handled through the voluntary NERC Event Analysis Program and do not need to be included in EOP-004 reporting. The risk of these minor events does not translate to a significant risk to the BES and does not need to be included in mandatory compliance and enforcement. 3. Under "transmission loss", misoperations involving 3 or more Transmission lines, transformers, or generators are reportable under EOP-004-4. Misoperation reporting is mandatory under PRC-004. Redundant reporting under EOP-004 is not needed and subjects entities to double jeopardy for compliance violations. 4. The NERC Event Analysis Program has matured over the past few years and is an excellent tool for industry to review, discuss, and develop lessons learned to improve reliability. Compliance obligations under the event type "Transmission loss" are no longer needed and are a detriment to reliability by taking the operational focus away from operation of the BES during these minor events to reporting when these reporting requirements are better handled through other existing programs.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Comments: Attachment 1, Page 10, 1st Row: Event Type: **BES Emergency resulting in voltage deviation on a Facility** – The voltage deviation range, as described in “Threshold for Reporting,” includes everything greater than -10% of nominal voltage which includes acceptable voltages. (e.g. For 115.0kV, everything greater than -10% would include 103.5 to 126.4kV) **Suggested Language for “Threshold for Reporting”:** A voltage deviation of < -10% OR > 10% of nominal voltage sustained for > 15 continuous minutes.	
Likes 0	
Dislikes 0	
Response	
The EOP SDT appreciates you comment about the voltage reporting requirement in the Threshold for Reporting and will change the language to “A voltage deviation of =/> 10% of nominal voltage sustained for > 15 continuous minutes.”	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At times there may be a need for a TOP to implement a public appeal for load reduction in certain areas of their system if there is a system operating limit that can only be controlled by reduced load. We recommend replacing “BA” with “Initiating BA or TOP.” The event types with multiple applicable entities such as, “Uncontrolled loss of firm load resulting from a BES Emergency”, and “System separation (islanding)” will most likely have the same event reported multiple times if the BA, TOP or RC are different entities. This has in the past been a source of confusion with the same event being reported multiple times. We recommend changing the Entity with Reporting Responsibility for the Event Type, “Uncontrolled loss of firm load resulting from a BES Emergency” to just the BA. We recommend changing the Entity with Reporting Responsibility for the Event Type, “System separation (islanding)” to just the BA. This would eliminate multiple reports for the same event, while still making sure the events are reported.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Reliability Standard EOP-011-1 (subject to future enforcement) puts the responsibility of having Public Appeals for load reduction in the BA’s Operating Plan to Mitigate Capacity Emergencies and Energy Emergencies; therefore, it should only be the BA reporting this event type in EOP-004. If an event applies to any of the entities listed as the “entities with reporting responsibilities,” then it is up to those entities to ensure reporting is done. Whether it be reporting the event themselves or delegating reporting responsibilities, this should all be covered in the entity’s event reporting Operating Plan.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	

Comment	
It appears that Attachment 1 is an effort to consolidate two separate reporting requirements. PJM believes the revision adds a bit of confusion. The ‘Automatic’ reporting section today states: via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS. PJM believes that the Standard should incorporate this clarity in the new EOP requirement so there is no confusion about reporting of ‘automatic’ load shed between 100-300MWs due to loss of BES Facilities (i.e. storms) which could be considered an emergency and also automatic, uncontrolled loss of 300MWs for any reason is reportable, which is why the 100-300MW presents confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT feels that the Threshold for Reporting is clear, the Responsible Reporting Entity will know if the Firm load shedding was done either manually, automatically or a combination of both.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	
Under physical threats to a facility, suspicious activity at a facility must be defined. I suggest suspicious activity be given its own row (removed from within physical threats to a facility). Specifically, “suspicious device or activity” is ambiguous. Further clarification on “suspicious activity” is needed. For example, does this include photography near a Facility? Also, Attachment 1 should specifically cover cyber related suspicious activity – for example, solicitation attempts or phishing calls at Facilities. There should also be instruction on what an Entity should do if they later realize the incident was NOT suspicious – for example, a prior reported incident which, after further investigation, turns out to be innocuous. The effect of using ambiguous terms and no mechanism for correcting incidents post investigation has left the industry with an output that contains more “trash” than value – many incidents that do not truly meet the definition of EOP 004 are sent out via EISAC which leads to the dilution of truly important incidents.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The EOP SDT feels the language in the Threshold for Reporting is clear as written. This is the language in the original reporting requirement the only change the EOP SDT made was the removal of “Do not report theft unless it degrades normal operation of a Facility.” Entities should define in their event reporting Operating Plan what they deem as suspicious, and report accordingly.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
(1) We believe the SDT is attempting to align Transmission Loss events with similar reportable criteria listed under the current NERC Event Analysis process. As identified within supportive documentation for this mature process, Category 1a Events caused by common disturbances affecting BES Facilities only refers to BES-defined lines, generators, and transformers. When capitalizing Facility in the context of this reportable criterion, this includes equipment like shunt compensators, circuit breakers, and busses. Furthermore, events caused by Misoperations are reportable under NERC Reliability Standard PRC-004, and could cause repetitive reporting in the process. If the SDT does not consider the outright removal of this event type from the EOP-004 reportable criteria, we recommend rephrasing the threshold for reporting a Transmission Loss event, as reportable to TOPs only, as “Unexpected loss, within its area and contrary to design or successful automatic reclosing, of three or more Transmission Facilities caused by a common disturbance.” (2) The reference to “=/>” in the reporting threshold for a BES Emergency resulting in a voltage deviation literally reads “equal to or greater than.” Is the intent of the SDT to identify a reporting threshold greater than ± 10% of nominal voltage? We propose using the symbol “≥” to reflect reporting a sustainable voltage deviation that is greater than or equal to ± 10% of nominal voltage over a continuous 15-minute period. (3) We believe the proposed reportable threshold reference under Generation Loss should be clarified to identify Forced Outages only. Forced Outages is listed under the NERC Glossary and identifies the removal of generation from service for either emergency reasons or unanticipated failures. We feel the incorporation of references to extreme weather patterns or fuel supply unavailability is unnecessary when used within this context.	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The drafting team is comprised of industry SMEs, NERC SMEs, and FERC observers, and the EOP SDT has conducted many discussions on this issue as a result of industry comments received; but finds that there remains a need for this reporting requirement. Transmission Loss event type in Attachment 1 closely aligns with the EAP. The EOP SDT collaborated with both the Events Analysis Subcommittee, as well as the United States Department of Energy, to better align reporting requirements of EOP-004, the EAP, and the OE-417. The intent of the EAP is to be used to promote a structured and consistent approach to performing event analyses in North America, it is a process for addressing event analysis and provides a lessons learned process and facilitates communication and information exchange among registered entities, NERC and its Regional Entities; it is a voluntary data-gathering tool; whereas the proposed Reliability Standard EOP-004-4 is mandatory. The EOP SDT appreciates you comment about the voltage reporting requirement in the Threshold for Reporting and will change the language to “A voltage deviation of =/> 10% of nominal voltage sustained for > 15 continuous minutes.” The EOP SDT discussed your comment and decided no changes were needed to the Generation loss Event Type category.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Overall the changes to the Standard are positive and WAPA appreciates the efforts of the SDT. However, there is still significant room for confusion regarding reportable Transmission Loss Events as a TOP with the change from Element to Facility. WAPA would very much appreciate examples within the standard that clarify events which would be reportable and events which would not be reportable.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy generally agrees with the SDT’s proposed revisions to EOP-004-3, Attachment 1: Reportable Events, but would like the SDT to consider the following: The addition of the word “staffed” in front of “BES control center…” becomes a qualifier to distinguish which control center is in scope for reporting to this category. An entity may have more than one control center that is “staffed” but we believe that the control center that is responsible for performing Real-time functions responsible for reliability is the control center that is in scope for when the threshold for complete loss of interpersonal Communication capability has been lost is met. Additionally, the term “control center” is not capitalized. We suggest that the term be capitalized to align with the glossary definition of Control Center and to align with the use Control Center in category 1h as it applies to the loss of monitoring or control at a Control Center. It is not necessary to have BES in front of Control Center because it is already included in the NERC definition. In summary, CenterPoint energy offers the following suggestions for the Event Type and Threshold for Reporting: Event Type - Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a Control Center. Threshold for Reporting - Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting a staffed Control Center responsible for performing Real-time functions for the reliability of its BES for 30 continuous minutes or more.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The EOP SDT team reviewed your comment about removing "its staffed" related to monitoring or control and Interpersonal/Alternative Interpersonal Communications. The team held many discussion on this topic related to staffed or not staffed; and, yes, it is important to the capability there, but if the site is not staffed the responsible entity will not be aware of the issue plus if you are not actively operating from the site there is no impact on reliability. The team is sure once the issues are identified the responsible entity will resolve the situation. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The NSRF believes we discovered a compliance concern that may cause entities to be non-compliant with Attachment 1, Event Type of *Transmission loss*. With the use of Facility (and Element) in threshold for reporting, a Transmission Operator may not be aware that the NERC defined term of Facility also contains "a generator". Even though Event Type *Generation loss* is predicated on a MW threshold, a *Transmission loss* event also contains generators. So, a TOP may lose 2 BES Transmission Facilities AND a BES Generator is tripped (due to the same Event), the TOP has then met the loss of "three or more BES Facilities" and is required to make a report per EOP-004-4. Either the SDT or NERC should publically post this clarification so all TOPs understand their obligations to the current enforceable EOP-004-2 and any further enforceable EOP-004. BES Elements (lines, transformers, and I5 reactors) that operate as a single Facility should be counted as one Facility. This is predicated on the definition that a Facility is "a set of…".	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your comment regarding Transmission Loss in Attachment 1. The previous draft revision from “Elements” to “Facilities” was to align with the EAP. Some examples of Transmission loss can be found on the NERC website for Event Analysis Program; specifically, Addendum for Category 1a Events. If further examples or questions arise, contact your Regional Entity.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Draft Standard EOP-004-4 Attachment 1, under table heading “Event Type”, Reclamation respectfully suggests consistent application of the replacement of “a” with “its” when referencing the Responsible Entity’s ownership, to be consistent with EOP-004-4 Attachment 2’s use of “its”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under damage or destruction of “a” Facility, the Event Type is deliberately listed as “a” Facility because the intent is to report on “all” Facilities in its RC/BA/TOP area.	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - Andrew Pusztai	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed revisions to EOP-004-3, Attachment 2? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	
I suggest suspicious activity be given its own row.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT finds that suspicious activity within Event Types: "Physical threats to its Facility and Physical threats to its BES control center" are clear as written in the Threshold for Reporting and does not require its own row.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Please see Texas RE's comment for #2.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see response to Question 2.	
Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the language should only refer to required event reporting to Operating Plan entities (e.g. NERC and/or DOE) within the reporting period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT finds that the Responsible Entity can define who the entities they report are within their event reporting Operating Plan.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	Yes
Document Name	
Comment	
Reclamation suggests consistent application of the replacement of “a” with “its” as it pertains to the Responsible Entity’s ownership.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under damage or destruction of “a” Facility, the Event Type is deliberately listed as “a” Facility because the intent is to report on “all” Facilities in its RC/BA/TOP area.	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Depending on the changes (if any) made to the recommendations stated in Question 2 above for Event Type "Transmission loss", Attachment 2 will need to be revised accordingly.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy suggests that the "Tasks" in Attachment 2 Event Reporting Form align with the Event Types in Attachment 1 if revised by the SDT.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Attachment 2 has been updated.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	Proposed_EOP-004-4_Attachment2.docx
Comment	
We find the proposed two-page format of the Attachment 2 form impractical. We offer a single page solution, as an attachment and proof that this information can be condensed accordingly.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Formatting has been changed to reduce Attachment 2 to a one-page document.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - Andrew Pusztai	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Olson - Portland General Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tony Eddleman - Nebraska Public Power District - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watkins - Michael Watkins On Behalf of: Pawel Krupa, Seattle City Light, 1, 4, 5, 6, 3; - Michael Watkins	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

4. Please provide any additional comments you have on the proposed revisions and clarifications to EOP-004-3.	
Ryan Buss - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) Based on the specifics of Attachment 1, we believe there is sufficient information available to include an applicability section within the standard pertaining to Facilities. The intent of this standard is to not capture events occurring on non-BES identified facilities. This would include reporting on small generating resources or dispersed power producing resources with nameplate ratings under 20 MVA or aggregate nameplate ratings under 75 MVA that are connected to a common connection point at 100 kV or above. (2) We question the VSL for Requirement R2 identifying a severity for when a Responsible Entity fails to submit an event report within 24 hours. We ask the SDT to clarify if the severity is based on 24 hours of the event's discovery or within 24 hours of the event's conclusion, independently of the expectation already proposed within the requirement text.	

(3) From the last commenting period for this draft standard revision, we previously recommended the implementation of an event reporting software tool on the NERC website providing capabilities to notify applicable Regional Entities and the DOE. We thank the SDT for its efforts to align event reporting activities with the DOE. However, based on the SDT's response to our comments, we are left with the impression that no automated mechanism is available to share event notifications submitted to the DOE with required Regional Entities, Reliability Coordinators, law enforcement, and other governmental authorities per Requirement R1. We believe a preventable human performance issue could be diverted through the development of a centralized portal that would disperse event reports to appropriate entities when necessary. We again ask the NERC Standards Developer assigned to this project to share this comment with NERC's IT department to see if a viable solution is available or could be developed.

(4) We thank you for this opportunity to provide feedback.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Attachment 1, as it relates to Facilities, is clear as written. A Facility is defined in the NERC Glossary as; "A set of electrical equipment that operates as a single BES Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." The EOP SDT has updated the VSLs for Requirement R2. NERC Events Analysis has been forwarded your comment regarding implementation of an event reporting software.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion

Answer	
Document Name	

Comment

R2 of EOP-004-4 state:

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan:

-by the later of 24 hours of recognition of meeting an event type threshold for reporting

or

-by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

The VSL Section state:

The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting.

By example, if an event occurred at midnight (12 a.m. Tuesday), the entity can submit a report by the end of the next business day (4 p.m. local time will be considered the end of the business day) which is Wednesday 4p.m. That means 40 hours after the event.

We suggest to remove this paragraph "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR" of the Lower VSL.

We suggest also modifying the moderate VSL as following: "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 40 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting."

1. In the section below, not sure why "Event Report" is capitalized? It seems that this "NOTE" intends to give an entity flexibility on the reporting timing, "under certain adverse conditions", by differentiating between issuing a "written Event Report" and a "notification" (still to be done within timing requirements of R2), but I'm not sure this is the reasons for capitalizing "Event Report"?

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1

2. For SDT's consideration - Event Types in the Attachment 1 do not seem to capture GOP BES control centers (either evacuation or physical threats)?

· By capitalizing "Facility" in the Event Type for a "Physical Threat to its Facility", since this term is defined in the NERC Glossary (and does not capture control center in the definition), this category excludes GOPs from reporting physical threats to their BES control centers under EOP-004.

· By excluding GOPs from the "Entity with Reporting Responsibility" list in the "Unplanned BES control center evacuation" Event Type, this category excludes GOPs from reporting evacuations from their BES control centers under EOP-004.

· Same as the bullet above for the "Complete loss of Interpersonal Communication capability at a BES control center"

Not sure if this is an intentional omission? CIP standards explicitly identify GOP control centers (High, Medium and Low Impact Rating) as subject to CIP requirements. CIP requirements are being implemented recognizing that there is an impact on BES from a CIP incident on a GOP control center, but EOP-004 doesn't capture non-cyber events associated with the same facilities for reporting requirements – seems inconsistent. At least High Impact GOP control centers, under the "Threshold for Reporting" should be considered for reporting requirements under EOP-004, for the events identified above. This comment is being submitted recognizing that the current version of EOP-004-2 does not required this reporting either, for the same reasons identified in the three bullets above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT updated the VSLs for Requirement R2. The first paragraph of EOP-004, Attachment 1, has been updated. The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers. In addition, there is no specific requirement in CIP-006 to report any physical threats to a Facility. CIP-006 says to refer to CIP-008 Cyber Security response plan. The Cyber Security response plan requires notification to E-SIAC only, which is not related to EOP-004 reporting.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
In its previous comments, Texas RE requested that the SDT provide the rationale for adopting a 12-month implementation timeframe. In particular, Texas RE noted that "Given that registered entities presently are required to submit event reports under the current version of EOP-004 and the revised version largely narrows the scope of such reporting activities, it is unclear why a 12-month implementation period is necessary." With this comment, Texas RE sought to understand the basis for the SDT's conclusion that a 12-month period was necessary to give entities appropriate time to address the revised Standard requirements. Rather than provide a rationale in its response, the SDT merely noted that its intent is for the 12-month Implementation Plan "was to give all entities an appropriate time frame for implementation." Texas RE therefore reiterates its request that the SDT provide a substantive basis for its determination that a 12-month time frame is appropriate. In response, the SDT could describe the additional compliance obligations for entities for the revisions, whether these will impose additional costs, require additional staffing, or other compliance burdens that serve as the basis for its conclusion.	
Likes 0	
Dislikes 0	
Response	
The Implementation Plan takes into account any barriers to implementation. The EOP SDT intent for the twelve-month Implementation Plan was to give all entities an appropriate time frame for implementation. Based on the EOP SDT's expertise, there are multiple processes that a NERC standard procedure has to go through and evaluated by an entity prior to being finalized, trained on, and approved. This standard would require changes to processes/procedures and training shift workers which requires ample time; and, therefore, a 12-month Implementation Plan is required.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	

We suggest capitalizing the term **"control center"** as it's defined in the NERC Glossary of Terms. Additionally, the terms "Reliability Coordinator (RC)", "Balancing Authority (BA)", and "Transmission Operator (TOP)" (applicable in the **Entity with Reporting Responsibility sections of Attachment 1)** are terms included in the definition of the term **"Control Center"** which provides more details on why the term should be capitalized throughout Attachment 1.	
Likes 0	
Dislikes 0	
Response	
The EOP SDT reviewed the defined term for Control Center (effective 7/1/2016 as identified in CIP standards) and GOP is included in this definition. The defined term is not applicable, given that the GOPs were not originally identified in Attachment 1 or Attachment 2 as an entity with reporting responsibilities for control center event types. Although the GOPs have other reporting responsibilities, they have no event reporting responsibility for control center event types. There is also not a currently-enforced standard that requires GOPs to have Control Centers or backup Control Centers.	
Sing Tay - Sing Tay On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

R2 of EOP-004-4 state:

Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan:

-by the later of 24 hours of recognition of meeting an event type threshold for reporting

or

-by the end of the Responsible Entity’s next business day (4 p.m. local time will be considered the end of the business day).

The VSL Section state:

The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting.

Based on this example, if an event occurred at midnight (12 a.m. Tuesday), the entity can submit a report by the end of the next business day (4 p.m. local time will be considered the end of the business day) which is Wednesday 4p.m. That means **40** hours after the event. On the Lower VSL, Hydro-Quebec TransEnergie suggest to remove this paragraph "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR" . On the Moderate VSL, Hydro-Quebec TransEnergie suggest modifying as following: "The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 40 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The EOP SDT updated the VSLs for Requirement R2.	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	
Document Name	
Comment	
The VSLs for R2 need to reflect the change in reporting deadlines to accommodate the reporting entity's next business day	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The EOP SDT has updated the VSLs for Requirement R2.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5	

Answer	
Document Name	
Comment	
"Suspicious device or activity" in Attachment 1 is not defined even though Suspicious is capitalized. The NERC Glossary of Terms does not define "Suspicious" either.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. "Suspicious" is capitalized because it is the first word in a new sentence. It was not the intent of the EOP SDT for "suspicious" to be defined.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-008-2 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/30/2016 – 08/15/2016

Anticipated Actions	Date
10-day final ballot	11/30/2016 – 12/09/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority
5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data exchange capabilities.

1.2.3. Interpersonal Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

  1.1. **Compliance Enforcement Authority:**
  "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

  1.2. **Evidence Retention:**
  The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

  The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

  - Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
  - Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
  - Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Measurement M3.
  - Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a

facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in effect document and any such documents in effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				primary control center functionality.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-008-2 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/30/2016 – 08/15/2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~06/22/2016 – 08/08/2016~~
~~45-day formal comment period with additional ballot~~	~~08/30/2016 – 10/14/2016~~
10-day final ballot	11/~~01~~30/2016 – ~~11~~12/~~11~~09/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Balancing Authority
5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data ~~communications~~exchange capabilities.

1.2.3. Interpersonal Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards ~~that depend on~~are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~ are applicable to the primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively~~. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to ~~-~~a Balancing Authority's or Transmission Operator's primary control center functionality ~~respectively~~ in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality ~~at least once every 15 calendar months~~. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved ~~at least once every 15 calendar months~~annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual~~a~~ test of its Operating Plan that ~~at least once every 15 calendar months and shall document the results from such a test. This test shall~~ demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in ~~force~~ effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in ~~force~~ effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has

demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively~~ in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in ~~force~~ effect Operating Plan for backup functionality, has been reviewed and approved ~~at least once every 15 calendar months~~annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in ~~force~~ effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in ~~force~~ effect document and any such documents in ~~force~~ effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Operator's primary control center functionality ~~respectively~~.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved ~~at least once every 15 calendar months~~. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but it did not document the results. OR, The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted ~~a~~an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~. OR, The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 0.5 continuous hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
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Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

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Anticipated Actions	Date
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NERC Board (Board) adoption	February 2017

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Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-~~1~~2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entit~~y~~ies:

   4.1.1. Reliability Coordinator~~.~~

   4.1.2. Transmission Operator~~.~~

   4.1.3. Balancing Authority~~.~~

~~5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.~~

5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing "data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include ~~the following, at a minimum~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality ~~for the time it takes to restore the primary control center functionality.~~.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include~~, at a minimum:~~:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data ~~communications.~~ exchange capabilities.

~~**1.1.1.** Voice communications.~~

1.2.3. Interpersonal Communications.

~~**1.2.3.**~~ **1.2.4.** Power source(s).

~~**1.2.4.**~~ **1.2.5.** Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include ~~at a minimum~~:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards ~~that depend on~~are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

~~M1.~~M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality~~ respectively.~~ . To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~**B. Measures**~~

~~6. M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.~~

~~7. M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.~~

~~8. M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.~~

~~9. M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.~~

~~10. M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.~~

~~M2.~~M1. ~~M6.~~ ~~Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.~~

~~M3.~~M1. ~~M7.~~ ~~Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.~~

~~M4.~~M8. ~~M8.~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:

~~2. Regional Entity.~~

~~**1.1. Compliance Monitoring and Enforcement Processes:**~~

~~3. Compliance Audits~~

~~4. Self-Certifications~~

~~5. Spot Checking~~

~~6. Compliance Violation Investigations~~

~~7. Self-Reporting~~

~~8. Complaints~~

~~**1.2. Data Retention**~~

~~The Reliability Coordinator, Balancing Authority, and Transmission Operator~~ "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall ~~retain~~keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in ~~force~~effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in ~~force~~effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.

- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively~~ in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in ~~force~~effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in ~~force~~effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and ~~one~~the previous ~~year~~calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup

functionality would last for more than six calendar months shall retain evidence for the current in ~~force~~effect document and any such documents in ~~force~~effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

~~8.1.~~1.3. ~~Additional~~ Compliance ~~Information~~ Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~None.~~Violation Severity Levels

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality.
R4.	N/A	N/A	N/A	~~9.~~ The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging,

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively.~~ .
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

R #	Violation Severity Levels			
~~R#~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
			than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

~~**10.**~~

~~11.~~

D. ~~E.~~ Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~2009 - 2010	~~Revisions for~~ Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board ~~of Trustees~~	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval~~.~~	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3 Requirement R1,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		EOP-005-2 Requirement R7, is redundant to EOP-005-3 Requirement R1.
EOP-005-2, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan. The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.	The EOP SDT revisions harmonize the use of “BES modification” and clarify the timing for unplanned permanent and planned permanent BES modifications.
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	“Implementation date” was revised to “effective date” to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady	The sentence, “This shall be completed every five years at a minimum” was revised to: “This shall be completed at least once

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	every five years" to eliminate any ambiguity in the prior language.
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training	The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	annually for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority.	the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. Federal Energy Regulatory Commission (Commission) Order no. 749:

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every 24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	*"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify "unique tasks."
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every 24 calendar months to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and	"Two calendar years" was revised to "24 calendar months" for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
bus. The training program shall include training on the following:	energizing a bus. The training program shall include training on the following:	
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. . Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	**1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area with Transmission Operators in other Reliability Coordinator Areas and with Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4. .	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4 Part 4.1.	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" for clarity.
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3,

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk*	"To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	*Factor = Medium] [Time Horizon = Operations Planning]*	

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. ~~The EOP SDT removed the language: "*…to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System*" in Requirement R1, as it is covered in Requirement R1, Part 1.8.~~ Due to the addition of the word "implement," the phrase, "Real-time

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3~~,~~ Requirement R1, EOP-005-2~~,~~ Requirement R7, is redundant to EOP-005-3~~,~~ Requirement R1.
EOP-005-2, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1 Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator ~~at least once each 15 calendar months~~annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.		Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall update and submit its revised restoration plan to ~~to~~ its Reliability Coordinator for approval, ~~that~~when the revision would change ~~the~~its ability to implement its restoration plan, as follows~~Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. ~~This language creates two ambiguities. First, the phrase: "... that would change the implementation of its restoration plan" appeared to apply to both types of changes; however, no time frame is specified for~~

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		~~updating the restoration plan for a planned BES modification. One could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications.~~ ~~Second, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Some "system modifications" can include "BES modifications". Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.~~ ~~For clarity, the EOP SDT revise the language in this Requirement to require a TOP to update its restoration plan to only reflect System modifications that affect its ability to implement its restoration plan as describe in Requirement R1 Parts. The intent is not to capture minor modifications that would have no impact on the implementation of a restoration, such as element number changes or device changes~~

Standard: EOP-005-3		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
		~~that have no significance to the implementation of the plan.~~ The changes made in Requirement R4 and the requirement parts do not refer to outages. The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within ~~No more than~~ 90 calendar days after identifying ~~the Transmission Operator identifies~~ any unplanned permanent ~~System~~ BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements ~~in order to meet~~	The EOP SDT revisions harmonize the use of "BES modification" and clarify the timing for unplanned permanent and planned permanent BES modifications.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~the Reliability Coordinator approval requirement~~ per EOP-006~~No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications~~.	
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation*	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation*	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Risk Factor = Medium] [Time Horizon = Long-term Planning]	*Risk Factor = Medium] [Time Horizon = Long-term Planning]*	
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following:	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training ~~at least once each 15 calendar months~~annually for its System Operators. This training program shall include training on the	~~The language, "…at least once each 15 calendar months…" was added to provide clarity and to align training with the timing for updates to the restoration plan.~~ The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor = Medium] [Time Horizon = Operations Planning] **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority. ~~for Area Control Error and Automatic Generation Control.~~	Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every ~~two calendar years~~24 calendar months to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		periodic review templates and the SAR) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify "unique tasks."
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every 24 calendar months to each of its operating personnel responsible for the startup of its	"Two calendar years" was revised to "24 calendar months" for consistency in the standards.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Resource generation units and energizing a bus. The training program shall include training on the following:	Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, ~~maintain,~~ and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. . Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	*= Operations Planning, Real-time Operations]* **1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area~~,~~ with ~~adjacent~~ Transmission Operators in other Reliability Coordinator Areas~~,~~ and with ~~adjacent~~ Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4. .	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4 Part 4.1.	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" for clarity.
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop~~, maintain,~~ and implement" to

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop~~, maintain,~~ and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program~~, at least once each 15 calendar months~~ annual~~,~~ System restoration training for its System Operators. This training program shall	~~Language for timeframe was added for clarity.~~ "To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing "data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
~~EOP-008-1, Requirement R5~~ ~~**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~EOP-008-2, Requirement R5~~ ~~**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~
~~EOP-008-1, Requirement R7~~ ~~**R7.** Each Reliability Coordinator, Balancing~~	~~EOP-008-1, Requirement R7~~	~~The language, "…at least once each 15 calendar months…" was added to provide clarity.~~

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
~~Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	~~**R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~	

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is a requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels
VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is a requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to the primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively~~.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved ~~at least once every 15 calendar months~~. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but it did not document the results. OR The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~. OR The responsible entity conducted ~~a~~ an annual test of its Operating Plan for backup functionality ~~at least once every 15 calendar months~~, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement

Project 2015-08 Emergency Operations
EOP-008-2

Final Ballot Open through December 9, 2016

Now Available

A final ballot for **EOP-008-2 – Loss of Control Center Functionality** is open through **8 p.m. Eastern, Friday, December 9, 2016**.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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BALLOT RESULTS

Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 FN 2 ST
Voting Start Date: 11/30/2016 10:08:26 AM
Voting End Date: 12/9/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 281
Total Ballot Pool: 301
Quorum: 93.36
Weighted Segment Value: 93.17

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	78	1	67	0.944	4	0.056	0	2	5
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	65	1	52	0.881	7	0.119	0	1	5
Segment: 4	17	1	13	0.867	2	0.133	0	0	2
Segment: 5	70	1	59	0.922	5	0.078	0	3	3
Segment: 6	50	1	43	0.915	4	0.085	0	0	3
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	301	6.9	253	6.428	22	0.472	0	6	20

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine	Colby Bellville	Negative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Abstain	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 301 of 301 entries

Previous 1 Next

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/26/2016 – 12/09/2016
10-day final ballot	12/28/2016 – 01/06/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Generator Operators
     - **4.1.3.** Transmission Owners identified in the Transmission Operators restoration plan
     - **4.1.4.** Distribution Providers identified in the Transmission Operators restoration plan
5. **Effective Date:** See the Implementation Plan for EOP-005-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for System restoration that are coordinated with its Reliability Coordinator’s high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform:

(1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

R4. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation, such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. .

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in effect since its last compliance audit for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in effect since its last compliance audit on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator prior

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from its Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator	N/A	The Transmission Operator and Generator Operator

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.		with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in its Reliability Coordinator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for ~~a 45-day formal comment period with~~final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/~~25~~26/2016 – 12/~~08~~09/2016
10-day final ballot	12/~~27~~28/2016 – 01/~~10~~06/2017
NERC Board (Board) adoption	February 2017

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Term(s):

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A. Introduction

1. **Title:** System Restoration from Blackstart Resources

2. **Number:** EOP-005-3

3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Generator Operators

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan

5. **Effective Date:** See the Implementation Plan for EOP-005-3.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for System restoration that are coordinated with ~~the~~ its Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~ its Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with ~~the~~ its Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform:

(1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities. ~~Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.~~

~~The changes made in Requirement R4 and the requirement parts do not refer to outages.~~ The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to ~~update and~~ submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to ~~update and~~ submit changes that do not substantively change the restoration plan~~, the TOP's ability to implement the plan,~~ or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, ~~or~~ device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and ~~draft~~ EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

R4. Each Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to ~~the~~ its Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has ~~updated its restoration plan and~~ submitted ~~it~~ the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation, such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations~~,~~ back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

R8. Each Transmission Operator shall include within its operations training program, annual System restoration training ~~-~~for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with ~~the~~ its Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every ~~24 calendar months~~two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every ~~24 calendar months~~ two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, ~~and~~ energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

R16. Each Generator Operator shall participate in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~ its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M16. Each Generator Operator shall have evidence that it participated in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time

since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in effect since the last ~~monitoring activity~~compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of a~~n updated~~ revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by ~~the~~ its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~monitoring activity~~compliance audit, as well as one previous ~~monitoring activity~~compliance audit period for Requirement R10, Measure M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. ~~it shall keep information related to the non-compliance until found compliant.~~

The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

If a Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. ~~it shall keep information related to the non-compliance until found compliant~~.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in effect since its last ~~monitoring activity~~compliance audit for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in effect since its last ~~monitoring activity~~compliance audit on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. ~~it shall keep information related to the non-compliance until found compliant.~~

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~monitoring activity~~compliance audit for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. ~~it shall keep information related to the non-compliance until found compliant.~~

The Compliance Enforcement Authority shall keep the last ~~monitoring activity~~compliance audit records and all requested and submitted subsequent ~~monitoring activity~~compliance audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~ its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator ~~updated and~~ submitted its revised restoration plan to ~~the~~ its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator ~~updated and~~ submitted its revised restoration plan to ~~the~~ its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification. ~~.~~	The Transmission Operator has failed to ~~update and~~ submit its revised restoration plan to ~~the~~ its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to ~~update and~~ submit its revised restoration plan

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to ~~the~~ its Reliability Coordinator prior to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a ~~24-calendar-month~~two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year~~24-calendar-month~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 two-calendar-year~~24-calendar-month~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year~~24-calendar-month~~ period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				from ~~the~~ its Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	restoration plan within 24 hours but did make the notification within 48 hours.	restoration plan within 48 hours but did make the notification within 72 hours.	restoration plan within 72 hours but did make the notification within 96 hours.	restoration plan for more than 96 hours.
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		year~~24-calendar-month~~ period.	yeart~~24-calendar-month~~ period.	
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~ its Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-005-3 is being posted for final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/26/2016 – 12/09/2016
10-day final ballot	12/28/2016 – 01/06/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources

2. **Number:** EOP-005-~~2~~3

3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ~~a~~enss~~s~~ure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators~~.~~

   4.1.2. Generator Operators~~.~~

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan~~.~~

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan~~.~~

~~5. **Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

5. **Effective Date:** See the Implementation Plan for EOP-005-3.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall ~~have~~develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall ~~allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~shutdown area ~~to service,~~ to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for ~~s~~System restoration that are coordinated with ~~the~~its Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~its Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring ~~authority~~operations back to the Balancing Authority in accordance with ~~the~~its Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

~~**R3.**~~ Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. ~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~

~~**3.1.** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retirement approved by FERC effective January 21, 2014.)~~

~~R4.~~R3. ~~Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the

Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

R4. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval ~~within the same 90 calendar day period.~~ , when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

~~**M1.**~~**M4.** Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its ~~implementation~~effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years ~~at a minimum.~~ . Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

~~R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected~~Each Transmission Operator shall ~~implement~~have documentation, such as power flow outputs, that it has verified that its latest restoration plan~~. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize~~ will accomplish its ~~restoration strategies to facilitate restoration. *[Violation Risk Factor*~~

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

~~*= High] [Time Horizon = Real-time Operations]*~~

~~M2.~~M6. ~~Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or~~intended function in accordance with ~~the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~Requirement R6.

~~R8.~~R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- **~~8.1.~~7.1.** The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.
- **~~8.2.~~7.2.** A list of required tests including:
  - **~~8.2.1.~~7.2.1.** The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.
  - **~~8.2.2.~~7.2.2.** The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.
- **7.3.** The minimum duration of each of the required tests.

~~M3.~~M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

~~R9.~~R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan.~~. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~9.1.~~8.1. System restoration plan including coordination with ~~the~~its Reliability Coordinator and Generator Operators included in the restoration plan.

~~9.2.~~8.2. Restoration priorities.

~~9.3.~~8.3. Building of cranking paths.

~~9.4.~~8.4. Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

~~R10.~~R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

~~R11.~~R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

~~R12.~~R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

~~R13.~~R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

~~R14.~~R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

~~R15.~~R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- **~~15.1.~~14.1.** Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement ~~R9~~R7.
- **~~15.2.~~14.2.** Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

~~R16.~~R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~16.1.~~15.1. System restoration plan including coordination with the Transmission Operator~~.~~

~~16.2.~~ The procedures documented in Requirement ~~R14.~~

~~**R17.** Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~

~~C. Measures~~

~~**M4.** Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.~~

~~**M5.** Each Transmission Operator shall have evidence such as e-mails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.~~

~~**M6.** Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, e-mails with receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.~~

~~**M7.** Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails with receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.~~

~~**M8.** Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.~~

~~**M9.** Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.~~

~~**M10.** If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.~~

~~**M11.** If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.~~

~~**M12.** Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R9.~~

~~**M13.** Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R10.~~

~~**M14.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R11.~~

~~17.1.~~15.2. ~~Each Transmission Operator shall have evidence, such as training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement~~ R12~~.~~

~~**M15.** Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R13.~~

~~**M16.** Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R14.~~

~~**M17.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within twenty-four hours of such changes in accordance with Requirement R15.~~

~~**M18.** Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R16.~~

~~M19.~~M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R1~~7~~5.

R16. Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M20.~~M16. Each Generator Operator shall have evidence~~, such as dated training records,~~ that it participated in ~~the~~its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R1~~8~~6.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity~~.~~

~~**1.4. Compliance Monitoring Period and Reset Time Frame**~~

~~Not applicable.~~

~~**1.5. Compliance Monitoring and Enforcement Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**Data**~~"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.

- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of ~~an updated~~a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current~~,~~ restoration plan approved by ~~the~~its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
  - ~~Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.~~
  - ~~Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.~~
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement ~~R9~~R7, Measure ~~M9~~M7.
- ~~Actual training~~Training program materials or descriptions for three calendar years for Requirement ~~R10~~R8, Measure ~~M10~~M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R1~~2~~0, Measure M1~~2~~0.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer. The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

~~The Transmission Operator, applicable Transmission Owner, and applicable Distribution provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Actual training~~Training program materials or descriptions and ~~actual~~ training records for three calendar years for Requirement ~~R11~~R9, Measure ~~M11~~M9.

If a Transmission Operator, applicable Transmission ~~o~~Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer. .

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in ~~force~~effect since its last compliance audit for Requirement R1~~3~~1, Measure M1~~3~~1.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in ~~force~~effect since its last compliance audit on procedures to start each Blackstart Resource~~s~~ and for energizing a bus for Requirement R1~~4~~2, Measure M1~~4~~2.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R1~~5~~3, Measure M1~~5~~3.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R1~~6~~4, Measure M1~~6~~4.
- ~~Actual training~~Training program materials and ~~actual~~ training records for three calendar years for Requirement R1~~7~~5, Measure M1~~7~~5.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R1~~8~~6, Measure M1~~8~~6.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance audit records.

1.3. ~~The~~ **Compliance Monitoring and Enforcement** ~~Authority shall keep~~**Program**

As defined in the ~~last audit records and all requested and submitted subsequent audit records~~NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~1.6. Additional Compliance Information~~

~~None.~~Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the ~~sub-requirements within the~~ requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. ~~OR~~	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~The Transmission Operator provided the information to all entities but was up to 10 calendar days late in doing so.~~	~~The Transmission Operator provided the information to all entities but was more than 10 and less than or equal to 20 calendar days late in doing so.~~	~~The Transmission Operator provided the information to all entities but was more than 20 and less than or equal to 30 calendar days late in doing so.~~	~~The~~ Transmission Operator ~~provided~~failed to provide at least half of the ~~information to all~~ entities ~~but was more than 30 calendar days late~~identified in ~~doing so~~its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ within 30 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 30 and less than or equal to 60 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 60 and less than or equal to 90 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan ~~or confirmation of no change~~ more than 90 calendar days after the ~~pre-determined~~mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator within 90 calendar days of an unplanned	The Transmission Operator ~~failed to update and submit~~submitted its revised restoration plan to ~~the~~its Reliability Coordinator ~~within more than 90~~between 91	The Transmission Operator ~~has failed to update and submit~~submitted its revised restoration plan to ~~the~~its Reliability Coordinator ~~within more than 120~~between 121	The Transmission Operator has failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator within ~~more than~~ 150

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~change.~~permanent System BES modification.	calendar days ~~but less than120~~and 120 calendar days of an unplanned ~~change.~~permanent System BES modification.	calendar days ~~but less than~~ and 150 calendar days of an unplanned ~~change~~permanent System BES modification.	calendar days of an unplanned ~~change.~~ permanent System BES modification. OR The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~its Reliability Coordinator prior to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its ~~implementation~~effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the ~~sub-~~	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the ~~sub-~~	The Transmission Operator performed the verification but did not complete it within the ~~five calendar year period~~required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~requirements.~~ requirement parts.	~~requirements.~~ requirement parts.		OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the ~~sub-requirements.~~ requirement parts.
~~R7.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not implement its restoration plan following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES. Or, if the restoration plan cannot be executed as expected, the Transmission Operator did not utilize its restoration plan strategies to facilitate restoration.~~
~~R8.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources have been utilized in~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~restoring the shut down area of the BES to service.~~
R~~9~~7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the ~~sub-requirements~~requirement parts of Requirement R~~9~~7.
R~~10~~8.	The Transmission Operator's training does not address one of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address two of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address three or more of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator has not included System restoration training in its operations training program.
R~~11~~9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement ~~R11 within a~~R9 two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement ~~R11~~R9 within a two-calendar-year period.
R1~~2~~0.	N/A~~.~~	N/A	N/A	The Transmission Operator has failed to comply with a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				request for ~~their~~its participation from ~~the~~its Reliability Coordinator.
R1~~3~~1.	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R1~~4~~2.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R1~~5~~3.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	Transmission Operator's restoration plan for more than 96 hours.
R1~~6~~4.	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in ~~R16.1.~~Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days ~~of~~after the request.	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 ~~days~~ to 90 calendar days after the request.	The ~~GOP~~Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R1~~7~~5.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R1~~7~~5 within a two-calendar-year period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Requirement R1~~7~~5 within a two-calendar-year period.	R1~~7~~5 within a two-calendar-year period.	R1~~7~~5 within a two-calendar-year period.	
R1~~8~~6.	N/A~~.~~	N/A	N/A	The Generator Operator failed to participate in ~~the~~its Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~its Reliability Coordinator.

~~E.~~D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	May 2, 2007	Approved by the Board of Trustees	Revised
2	~~TBD~~	Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new ~~R~~requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval~~.~~	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval~~.~~	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/26/2016 – 12/09/2016
10-day final ballot	12/28/2016 – 01/6/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator; and

7.2. Re-establishing the Interconnection.

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.

- The current, approved restoration plan and any restoration plans in effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program,	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for ~~a 45-day formal comment period with~~final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/~~25~~26/2016 – 12/~~08~~09/2016
10-day final ballot	12/~~27~~28/2016 – 01/~~10~~6/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of ~~approve~~ approval or ~~disapprove~~disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The coordination role of the Reliability Coordinator; and

7.2. Re-establishing the Interconnection.

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the

Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every ~~24 calendar months~~two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The current restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.

- The current, approved restoration plan and any restoration plans in effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. ~~it shall keep information related to the non-compliance until found compliant.~~

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program,	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-006-3 is being posted for final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	06/22/2016 – 08/08/2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	10/26/2016 – 12/09/2016
10-day final ballot	12/28/2016 – 01/6/2017
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** System Restoration Coordination

2. **Number:** EOP-006-~~2~~ 3

3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators~~.~~

~~5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall ~~have~~develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a ~~shut down~~shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

~~1.2. Operating Processes for restoring the Interconnection.~~

~~1.3. Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~

~~1.4. Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

~~1.5.~~1.2. Criteria and conditions for ~~reestablishing~~re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

~~1.6.~~1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

~~1.7.~~1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

~~1.8.~~1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

~~1.9.~~1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review ~~their~~its neighboring Reliability Coordinator's restoration plans~~.~~ and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If ~~the~~a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days~~.~~ of receipt of written notification.

~~M1.~~M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall ~~approve~~provide notification to the Transmission Operator of approval or disapprov~~e~~al, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the ~~implementation~~effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

~~M2.~~M6. Each Reliability Coordinator shall ~~work with its affected Generator Operators, and Transmission Operators~~have documentation such as ~~well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the~~ electronic receipts that it has made the latest copy of its restoration plan ~~cannot be completed as expected the~~ and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator ~~shall utilize its restoration plan strategies to facilitate~~Area available in its primary and backup control rooms and to each of its System ~~restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~ Operators prior to the effective date in accordance with Requirement R6.

~~**R7.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability~~

~~Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]~~

~~R8.~~R7. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan.~~ . This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~8.1.~~7.1. The coordination role of the Reliability Coordinator~~.~~; and

7.2. ~~Reestablishing~~Re-establishing the Interconnection.

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

~~R9.~~R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~9.1.~~8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

~~C. Measures~~

~~M1.~~Each Reliability Coordinator shall have ~~available a dated copy of its restoration plan in accordance with Requirement R1.~~

~~M9. Each Reliability Coordinator shall provide~~ evidence, such as ~~e-mails with receipts, posting to a secure web site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.~~

~~M10.M1. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.~~

~~M11. Each Reliability Coordinator shall provide evidence such as dated review signature sheets that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.~~

~~M12. Each Reliability Coordinator shall provide evidence, such as a review signature sheet or emails, that it has reviewed, approved or disapproved, and notified its Transmission Operator's within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.~~

~~M13. Each Reliability Coordinator shall have documentation such as e-mail receipts that it has made the latest copy of its restoration plan and copies of the latest approved~~

~~restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the implementation date in accordance with Requirement R6.~~

~~**M14.** Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.~~

~~**M15.** If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.~~

~~**M16.** Each Reliability Coordinator shall have an~~ dated electronic ~~or hard copy of its training records available showing that it has provided training in accordance with Requirement R9.~~

~~**M17.**~~**M8.** ~~Each Reliability Coordinator shall have evidence~~documents, that it conducted two System restoration drills, exercises, or simulations per calendar year ~~and that Transmission Operators~~ in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator ~~Operators included in the Reliability Coordinator's restoration plan were invited in accordance with Requirement R10.~~Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~Regional Entity.~~

~~**1.4. Compliance Monitoring Period and Reset Time Frame**~~

~~Not applicable.~~

~~**1.5. Compliance Monitoring and Enforcement Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.6. Data Retention**~~

~~The Reliability Coordinator~~"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- The current restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in ~~force~~effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in ~~force~~effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
  - ~~If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R7, Measure M7.~~
  - ~~If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R8, Measure M8.~~
- Actual training program materials or descriptions for three calendar years for Requirements ~~R9~~R7, Measure M~~9~~7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R10~~R8, Measure ~~M10~~M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until ~~found compliant.~~mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.2.~~1.3. ~~Additional~~ Compliance ~~Information~~ Monitoring and Enforcement Program

~~None.~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one ~~sub-~~requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two ~~sub-requirements~~requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the ~~sub-~~requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the ~~sub-requirements~~requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
~~R4~~R5.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~60~~45 calendar days of receipt.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~90~~60 calendar days~~.~~ of receipt.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did ~~resolve conflicts~~review and approve/disapprove the plans within ~~120~~90 calendar days~~.~~ of receipt.	The Reliability Coordinator did not review and ~~resolve conflicts with~~ approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators ~~within 120~~for more than 90 calendar days~~.~~ of receipt. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			restoration training within its operations training program, but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

~~R5.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.~~	~~The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt.~~ ~~OR~~ ~~The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt. .~~
~~R6.~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.~~	~~The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.~~

~~**R7.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ ~~OR~~ ~~When the restoration plan cannot be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate System restoration.~~
~~**R8.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.~~ ~~OR~~ ~~If the resynchronization could not be completed as expected, the Reliability Coordinator did not utilize its restoration plan~~

				~~strategies to facilitate resynchronization.~~
~~**R9.**~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the sub-requirements.~~	~~The Reliability Coordinator did not include the annual System restoration training within its operations training program.~~
~~**R10.**~~	~~The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~	~~The Reliability Coordinator did not invite a Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.~~	~~N/A~~	~~The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.~~

~~E.~~D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

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~~Nov. 1, 2006	Adopted by Board of Trustees	Revised
2	~~TBD~~	Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standard(s)

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirement(s)

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standard(s)

None.

Applicable Entities

EOP-005 — System Restoration from Blackstart Resources

- Transmission Operator
- Generator Operator
- Transmission Owners identified in the Transmission Operators restoration plan
- Distribution Providers identified in the Transmission Operators restoration plan

EOP-006 — System Restoration Coordination

- Reliability Coordinator

EOP-008 — Loss of Control Center Functionality

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing an outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

None.

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination
Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality
Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3 Requirement R1,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		EOP-005-2 Requirement R7, is redundant to EOP-005-3 Requirement R1.
EOP-005-2, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.	EOP-005-3, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.	EOP-005-3, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.	EOP-005-3, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	would change its ability to implement its restoration plan, as follows	System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The references to unplanned permanent and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a TOP to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.	The EOP SDT revisions harmonize the use of “BES modification” and clarify the timing for unplanned permanent and planned permanent BES modifications.
EOP-005-2, Requirement R5	EOP-005-3, Requirement R5	“Implementation date” was revised to “effective date” to clarify that System

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	**R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	The sentence, “This shall be completed every five years at a minimum” was revised to: “This shall be completed at least once every five years” to eliminate any ambiguity in the prior language. Based on comments received from industry, the issue was raised that Requirement R6, as written, could be misinterpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation could result in numerous simulations having to be performed, which was outside of the intention of the drafting team. To eliminate any unintentional

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		misinterpretation of Requirement R6, it was revised to: "Each Transmission Operator shall verify through analysis of actual events, **a combination of** steady state and dynamic simulations…"
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training annually for its System Operators. This training program shall include training on	The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional*

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority.	*Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time. "The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	standard is a revision back to the original language of EOP-005-2. Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."* The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the term “unique tasks.” The industry understands “unique tasks” to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify “unique tasks.”
EOP-005-2, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator’s restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	EOP-005-3, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator’s restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	“The Reliability Coordinator” has been updated to “its Reliability Coordinator” for consistency throughout the standard.
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource	The word “email” doesn’t capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
24 hours of such changes in accordance with Requirement R13.	capabilities within 24 hours of such changes in accordance with Requirement R13.	
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.
EOP-005-2, Measure R16 **R18.** Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.	EOP-005-3, Measure R16 **R16.** Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requested to do so in accordance with Requirement R16.	simulations if requested to do so in accordance with Requirement R16.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	**1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area with Transmission Operators in other Reliability Coordinator Areas and with other Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
.	requirements of Requirement R4 and Requirement R4 Part 4.1.	
EOP-006-2, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	EOP-006-3, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	To align the requirement to the measure in Requirement R5, Part 5.1.
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of	EOP-006-3, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the	"Implementation date" was revised to "effective date" for clarity.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration.		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as “a logical action that does not require a standard.” The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: “develop and implement” to EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor = High] [Time Horizon = Real-time Operations]		
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.	EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing “data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area ~~to service~~, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT to add the language "develop and implement" is for the TOP to develop its restoration plan and for the restoration plan to be utilized. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon. The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" and "be implemented to restore" to EOP-005-3 Requirement R1,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		EOP-005-2 Requirement R7, is redundant to EOP-005-3 Requirement R1.
EOP-005-2, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.	EOP-005-3, Requirement R1, Part 1.1 **1.1.** Strategies for System restoration that are coordinated with ~~the~~ its Reliability Coordinator's high level strategy for restoring the Interconnection.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.	EOP-005-3, Requirement R1, Part 1.3 **1.3.** Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~ its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.	EOP-005-3, Requirement R1, Part 1.9 **1.9.** Operating Processes for transferring operations back to the Balancing Authority in accordance with ~~the~~ its Reliability Coordinator's criteria.	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised to: "1.9 Processes for transferring **operations** ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		“The Reliability Coordinator” has been updated to “its Reliability Coordinator” for consistency throughout the standard.
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	“Implementation date” was revised to “effective date” to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Measure M2 **M2.** Each Transmission Operator shall have evidence such as emails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.	EOP-005-3, Measure M2 **M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.	The word “email” doesn’t capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is TOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.	EOP-005-3, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to	EOP-005-3, Requirement R4 **R4.** Transmission Operator shall ~~update and~~ submit its revised restoration plan to its Reliability Coordinator for approval, when	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	the revision would change its ability to implement its restoration plan, as follows	System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. ~~The changes made in Requirement R4 and the requirement parts do not refer to outages.~~ The references to unplanned permanent ~~unplanned~~ and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a ~~Responsible Entity~~TOP to ~~update and~~ submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to ~~update and~~ submit changes that do not substantively change the restoration plan~~, the TOP's ability to implement the plan,~~ or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		changes, ~~or~~ device changes, or administrative changes that have no significance to the implementation of the plan. The timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and draft EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.	EOP-005-3, Requirement R4, Parts 4.1 and 4.2 **4.1** Within 90 calendar days after identifying any unplanned permanent BES modifications. **4.2** Prior to implementing a planned permanent BES modification subject	The EOP SDT revisions harmonize the use of "BES modification" and clarify the timing for unplanned permanent and planned permanent BES modifications.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	to ~~the~~ its Reliability Coordinator approval requirements per EOP-006.	
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language. Based on comments received from industry, the issue was raised that Requirement R6, as written, could be misinterpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		interpretation could result in numerous simulations having to be performed, which was outside of the intention of the drafting team. To eliminate any unintentional misinterpretation of Requirement R6, it was revised to: "Each Transmission Operator shall verify through analysis of actual events, **a combination of** steady state and dynamic simulations…"
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1. R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2, Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5	The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R10. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2** Restoration priorities. **10.3** Building of cranking paths. **10.3** Synchronizing (re-energized sections of the System).	**R8.** Each Transmission Operator shall include within its operations training program, System restoration training annually for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with ~~the~~ its Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities. **8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition of Demand and resource balance within its area to the Balancing Authority.	Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*. Requirement R8, Part 8.5 has been revised to include language within the definition of BA, which was approved by the Board on 2/11/2016; pending FERC approval. The Board approved definition of Balancing Authority is: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time. "The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Requirement R11	EOP-005-2, Requirement R9	"Two calendar years" was revised to "24 calendar months" for consistency in the

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R11. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	**R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every ~~24 calendar months~~two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2. Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP. A rationale box was added to the requirement to clarify "unique tasks."
EOP-005-2, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	EOP-005-3, Measure M10 **M10.** Each Transmission Operator shall have evidence that it participated in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.
EOP-005-2, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as emails with receipts or registered mail	EOP-005-3, Measure M13 **M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or	The word "email" doesn't capture the universe of electronic receipts; verification for submitting entity, as opposed to receiving entity. Submitting entity is GOP.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.	
EOP-005-2, Requirement R17 **R17.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	EOP-005-3, Requirement R15 **R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every ~~24 calendar months~~two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.
EOP-005-2, Measure R16 **R18.** Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.	EOP-005-3, Measure R16 **R16.** Each Generator Operator shall participate in ~~the~~its Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~its Reliability Coordinator.	"The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Measure M16 **M16.** Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	EOP-005-3, Measure M16 **M16.** Each Generator Operator shall have evidence that it participated in ~~the~~ its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.	"…such as dated training records…" was deleted from the Measure for consistency with Measure M10. "The Reliability Coordinator" has been updated to "its Reliability Coordinator" for consistency throughout the standard.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-006-2 Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5. Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" in Requirement R1, Part 1.2 was removed in which the EOP SDT agreed with comments from industry. Requirement R1 already establishes that restoration efforts are complete when neighboring Transmission Operators are connected. The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	**1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area with Transmission Operators in other Reliability Coordinator Areas and with other Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.	EOP-006-3, Measure M4 **M4.** Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing	The language in Measure M4 was updated to align the timing requirements of Requirement R4 and Requirement R4 Part 4.1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
.	requirements of Requirement R4 and Requirement R4 Part 4.1.	
EOP-006-2, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	EOP-006-3, Requirement R5, Part 5.1 **5.1.** The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.	To align the requirement to the measure in Requirement R5, Part 5.1.
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of	EOP-006-3, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the	"Implementation date" was revised to "effective date" for clarity.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration.		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor = High] [Time Horizon = Real-time Operations]		
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.	EOP-006-2, Requirement R8, Part 8.1 **8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.	"Two calendar years" was revised to "24 calendar months" for consistency in the standards. This provides flexibility for training schedules and equipment availability. This revision to Draft 3 of the standard is a revision back to the original language of EOP-005-2.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.2 **1.2.2** Data communications.	EOP-008-2, Requirement R1, Part 1.2.2 **1.2.2** Data exchange capabilities.	The phrase "data exchange capabilities" is replacing "data communications in Requirement R1, Part 1.2.2 for the following reasons: COM-001-1 (no longer enforceable) enforceable covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data. The topic of data exchange has historically been covered in the IRO / TOP Standards.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications.	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid	EOP-008-2, Requirement R3 **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality. To avoid	Revised "depend on" to "applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
requiring a tertiary facility, a backup facility is not required during: • Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	requiring a tertiary facility, a backup facility is not required during: Planned outages of the primary or backup facilities of two weeks or less • Unplanned outages of the primary or backup facilities	
EOP-008-1, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.	EOP-008-2, Measure M3 **M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.	Revised "depend on" to "applicable to the." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.
EOP-008-1, Requirement R4	EOP-008-1, Requirement R4	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality.	**R4.** Each ach Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	primary control center to meet compliance with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality.
EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	EOP-008-1, Measure M4 **M4.** Each Balancing Authority and Transmission Operator shall provide dated	Revised "depend on" to "are applicable to." The intent was not to have the backup facility "depend on" the functions of the primary control center to meet compliance

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.	evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.	with Reliability Standards, rather to meet compliance for Reliability Standards that were met with the primary control center functionality need to be met with the backup control center functionality. The revision aligned the measure to the requirement.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three or more of the ~~r~~requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement part” and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing "implementation date" to "effective date" requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "implementation" with "effective" and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator prior to a planned permanent BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from its Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “their” with “its.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three or more of the ~~r~~equirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective” and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~ its Reliability Coordinator within 90 calendar days of an unplanned permanent ~~System~~ BES modification.	The Transmission Operator ~~updated and~~ submitted its revised restoration plan to ~~the~~ its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent ~~System~~ BES modification.	The Transmission Operator ~~updated and~~ submitted its revised restoration plan to ~~the~~ its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent ~~System~~ BES modification.	The Transmission Operator has failed to ~~update and~~ submit its revised restoration plan to ~~the~~ its Reliability Coordinator within 150 calendar days of an unplanned permanent ~~System~~ BES modification. OR The Transmission Operator failed to ~~update and~~ submit its revised restoration plan to ~~the~~ its Reliability Coordinator prior to a planned permanent BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “implementation” with “effective.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a ~~24-calendar-month~~two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year~~24-calendar-month~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year~~24-calendar-month~~ period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year~~24-calendar-month~~ period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from ~~the~~ its Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “their” with “its.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year~~24 calendar month~~ period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by ~~the~~ its Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	Moderate	High	Severe
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "implementation date" with "effective date." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the annual System restoration training within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing “annual” with “at least once each 15 calendar months” and by replacing “subrequirements” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

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Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-006-3 – System Restoration Coordination. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in a Real-time Operations and Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the Reliability Coordinator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Transmission operator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-006-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator has a restoration plan, but failed to implement it.

VSL Justifications for EOP-006-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Reliability Coordinator to distribute its most recent restoration plan and is administrative in nature. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for distribution of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R2) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to distribute restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2, but was 90 or more calendar days late, but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2, but was 120 calendar days or more late.

VSL Justifications for EOP-006-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to review its restoration plan within 13 months of the last review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

VSL Justifications for EOP-006-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Reliability Coordinator to review its neighboring Reliability Coordinator's restoration plan and provide written notification of conflicts discovered during the review. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding conflict resolution timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a neighboring Reliability Coordinator's restoration plan. This is a slightly revised requirement (EOP-006-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to review the neighboring Reliability Coordinator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts over 91 calendar days calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.

VSL Justifications for EOP-006-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Reliability Coordinator to review the restoration plans of Transmission operators within its reliability Coordinator Area. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a review the restoration plans of Transmission operators within its reliability Coordinator Area. This is an unrevised requirement (EOP-006-2, Requirement R5) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-006-3, R5	
Proposed VRF	**Medium**
	R5 contains only one objective which is to review the review the restoration plans of Transmission operators within its reliability Coordinator Area. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt, but did review and approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.

notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	

VSL Justifications for EOP-006-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Reliability Coordinator to have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having copies of the latest restoration plans. This is a slightly revised requirement (EOP-006-2, Requirement R6) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have copies of the latest restoration plans would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to have copies of the latest restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the implementation date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.

VSL Justifications for EOP-006-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "implementation date" with "effective date." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Reliability Coordinator to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding training topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for to inclusion within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This is an unrevised requirement (EOP-006-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

VRF Justifications for EOP-006-3, R7	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program, but did not address both of the requirements parts.	The Reliability Coordinator did not include the annual System restoration training within its operations training program.

VSL Justifications for EOP-006-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs were revised slightly by replacing "annual" with "at least once each 15 calendar months" and by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Reliability Coordinator to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. A violation of this requirement has been assigned a Medium VRF because, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part regarding requesting other entities to participate in the System restoration drills, exercises, or simulations and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for conducting two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. This is an unrevised requirement (EOP-006-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted would not be expected to adversely affect the

VRF Justifications for EOP-006-3, R8	
Proposed VRF	**Medium**
	electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective which is to conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-006-3, R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

VSL Justifications for EOP-006-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-006-3 deals with restoration plans similar to EOP-006-2. The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-006-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Consideration of Issues and Directives

Project 2015-08 Emergency Operations

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*	FERC Order Number 749	The Project 2015-02 Emergency Operations Periodic Review Team (EOP PRT), as well as the Project 2015-08 Emergency Operations Standards Drafting Team (EOP SDT) determined (through conducted outreach and comment questions/responses during postings of periodic review templates, the project SAR, and project postings) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the Transmission Operator (TOP), Transmission Owner (TO), and the Distribution Provider (DP). A rationale box was added to EOP-005-3, Rquirement R9 to clarify "unique tasks." **Rationale:** The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.
Clarify when system changes will trigger a requirement to update restoration plans. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for updating restoration	FERC-NERC-Regional Entity Joint Review of Restoration	The Project 2015-08 EOP SDT revised EOP-005-3, Requirement R4 and the requirement parts. The references to unplanned permanent and planned permanent BES modifications that will change the ability to implement the Reliability Coordinator (RC)-approved restoration plan are intended to require a TOP to

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
plans for all system modifications that would change the implementation of an entity's restoration plan for an extended period of time, not just permanent or planned system modifications. In considering these measures, the kinds of events that may warrant an update to the system restoration plan should be identified, taking into account the length of time the system is affected, as well as the overall objective of ensuring that restoration plans are generally flexible enough so that system modifications can be addressed without continuous updates.	and Recovery Plans. **Section IV.E**	update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RC's ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.
Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits.6 In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new	FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. **Section IV.G**	The EOP SDT discussed the recommendation to address the "…need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably…" The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan, these also have to be submitted to the RC for review, 3) include within its operations training program annual System restoration training

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
blackstart generator location or on redefinition of a cranking path).		for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC 1) has to review its restoration plan within 13 calendar months of the last review, 2) has to review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) has to review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed to system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System, and the RC is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, that both entities are continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation.
Operator training: Exercises on transferring control back to the balancing authority. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to	FERC-NERC-Regional Entity Joint Review of	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised in EOP-005-3, Requirement R1, Part 1.9 to the standard: "Processes for

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
address system restoration training and drilling for transitioning from transmission operator island control to balancing authority ACE/AGC7 control.	Restoration and Recovery Plans. **Section IV.H.**	transferring <u>operations</u> ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2015-08 Emergency Operations
EOP-005-3 and EOP-006-3

Final Ballots Open through January 6, 2017

Now Available

Final ballots for **EOP-005-3 - System Restoration from Blackstart Resource** and **EOP-006-3 - System Restoration Coordination** are open through **8 p.m. Eastern on Friday, January 6, 2017**.

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pools associated with this project can log in and submit their vote(s) here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 FN 3 ST
Voting Start Date: 12/28/2016 8:05:24 AM
Voting End Date: 1/6/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 283
Total Ballot Pool: 310
Quorum: 91.29
Weighted Segment Value: 83.65

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	80	1	56	0.789	15	0.211	0	2	7
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	66	1	49	0.817	11	0.183	0	2	4
Segment: 4	18	1	14	0.875	2	0.125	0	1	1
Segment: 5	74	1	48	0.8	12	0.2	0	3	11
Segment: 6	51	1	38	0.792	10	0.208	0	1	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	310	6.9	222	5.772	52	1.128	0	9	27

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Abstain	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Erick Barrios		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		None	N/A
5	Westar Energy	Laura Cox		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Negative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 310 of 310 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 FN 3 ST
Voting Start Date: 12/28/2016 8:06:03 AM
Voting End Date: 1/6/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 271
Total Ballot Pool: 295
Quorum: 91.86
Weighted Segment Value: 80.56

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	45	0.776	13	0.224	0	10	6
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	64	1	41	0.788	11	0.212	0	8	4
Segment: 4	17	1	9	0.75	3	0.25	0	4	1
Segment: 5	70	1	37	0.755	12	0.245	0	12	9
Segment: 6	49	1	30	0.789	8	0.211	0	9	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	295	6.9	179	5.559	49	1.341	0	43	24

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Robert Coughlin	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Negative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	John Hare	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Lori Folkman	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Abstain	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		None	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Erick Barrios		None	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		None	N/A
5	Westar Energy	Laura Cox		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 10-day final ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/09/2016
10-day final ballot period	01/24/2017 – 02/02/2017

Anticipated Actions	Date
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

    4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

    4.1.1. Reliability Coordinator

    4.1.2. Balancing Authority

    4.1.3. Transmission Owner

    4.1.4. Transmission Operator

    4.1.5. Generator Owner

    4.1.6. Generator Operator

    4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.” The NERC Glossary of Terms defines Alternative Interpersonal Communication as: “Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.”

Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load sheddingresulting from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

<table>
<tr><th colspan="3">EOP-004 Attachment 2: Event Reporting Form
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."</th></tr>
<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td>1.</td><td>Entity filing the report include:
Company name:
Name of contact person:
Email address of contact person:
Telephone Number:
Submitted by (name):</td><td></td></tr>
<tr><td>2.</td><td>Date and Time of recognized event.
Date: (mm/dd/yyyy)
Time: (hh:mm)
Time/Zone:</td><td></td></tr>
<tr><td>3.</td><td>Did the event originate in your system?</td><td>Yes ☐ No☐ Unknown ☐</td></tr>
<tr><td rowspan="2">4.</td><td colspan="2">Event Identification and Description:</td></tr>
<tr><td>(Check applicable box)
☐ Damage or destruction of a Facility
☐ Physical threat to its Facility
☐ Physical threat to its BES control center
☐ BES Emergency:
  ☐ firm load shedding
  ☐ public appeal for load reduction
  ☐ System-wide voltage reduction
  ☐ voltage deviation on a Facility
  ☐ uncontrolled loss of firm load
☐ System separation (islanding)
☐ Generation loss
☐ Complete loss of off-site power to a nuclear generating plant (grid supply)
☐ Transmission loss
☐ Unplanned evacuation of its BES control center
☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center
☐ Complete loss of monitoring or control capability at its staffed BES control center</td><td>Written description (optional):</td></tr>
</table>

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

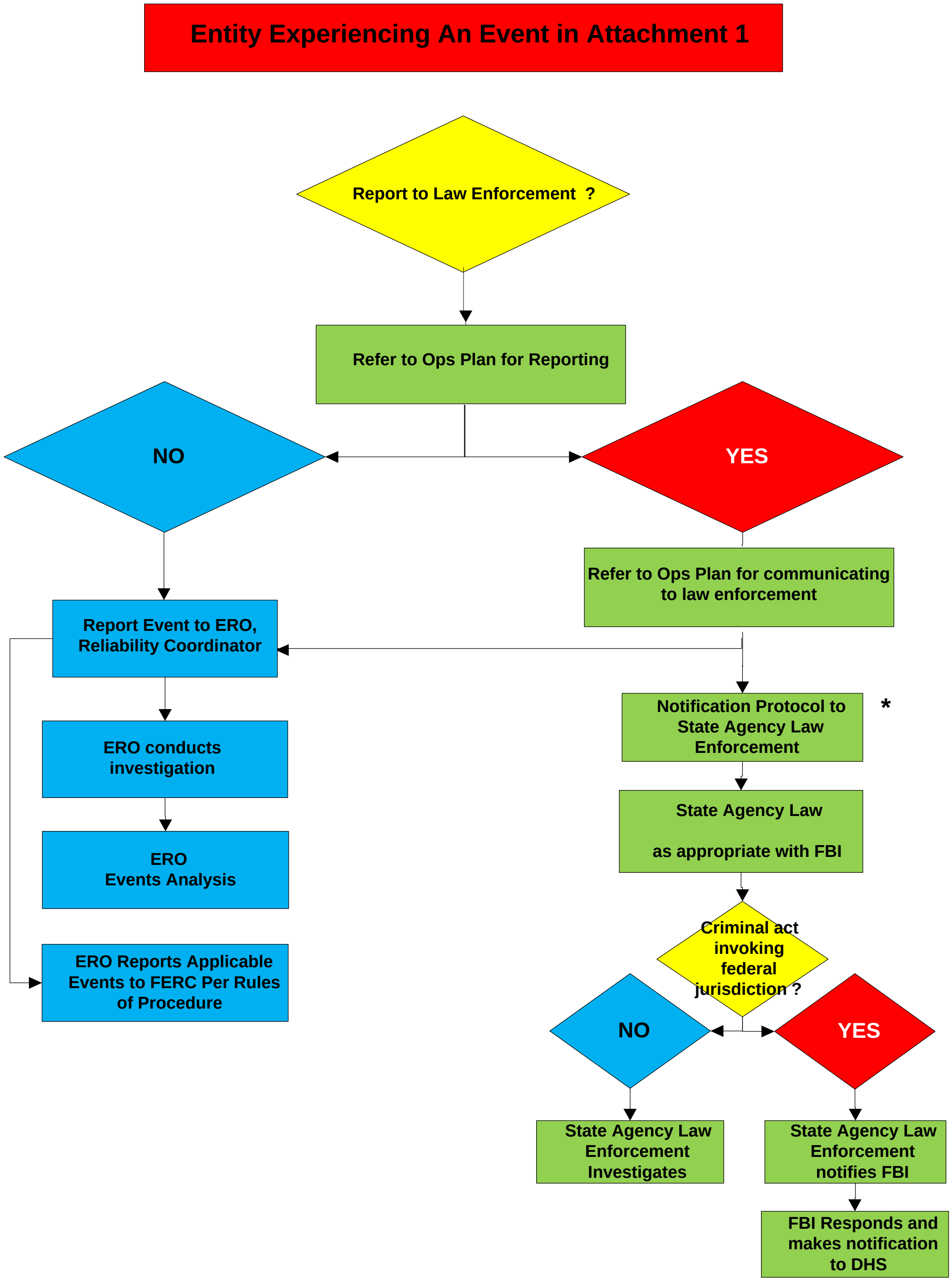
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a ~~45~~10-day final ~~formal comment period with~~ ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/09/2016
10-day final ballot period	01/24/2017 – 02/02/2017

Anticipated Actions	Date
~~10-day final ballot~~	~~01/05/2017 – 01/16/2017~~
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal~~more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~ 24 hours but less than or equal to 48 hours after ~~recognition of meeting an~~the timing requirement for submittal~~event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~ 72 hours after ~~recognition of meeting an~~the timing requirement for submittal~~event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~60~~ 72 hours after ~~recognition of meeting an~~the timing requirement for submittal~~event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written ~~Event~~ event ~~Report~~ report within the timing in the standard. ~~-~~In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more ~~to maintain the continuity of the BES~~.
Firm load shedding resulting from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> ~~±~~ 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 ~~Minutes~~ minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical ~~Threat~~threat to its Facility ☐ Physical ~~Threat~~threat to its BES control center ~~☐ System-wide voltage reduction~~ ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		Comments
	☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

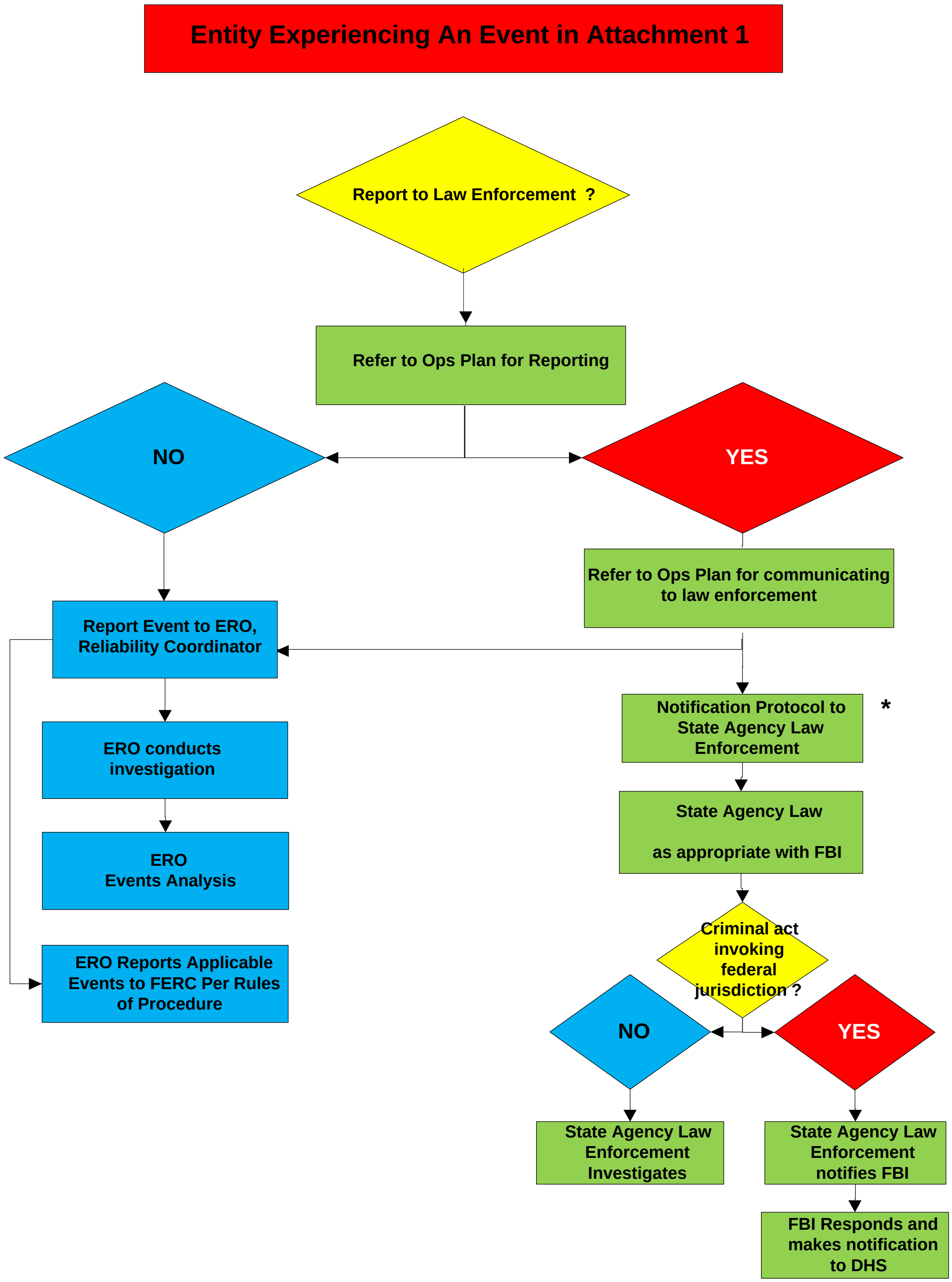
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

~~A.~~ Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 10-day final ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/09/2016
10-day final ballot period	01/24/2017 – 02/02/2017

Anticipated Actions	Date
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-~~3~~4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following ~~functional entities~~Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

~~5.~~ **Effective Date~~s~~:** See the Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme"~~

~~**5. 6. Background:**~~

~~6.~~5. ~~NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and~~ EOP-004 ~~Reliability Standards. The team was asked to consider the following:~~ -4.

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

B. ~~B.~~ Requirements and Measures

R1. ~~**R1.**~~ Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2~~ ~~3~~4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. ~~**M1.**~~ Each Responsible Entity will have a dated event reporting Operating Plan that includes~~, but is not limited to the~~ protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. ~~**R2.**~~ Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan ~~within~~by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM~~(4 p.m. local time ~~on Friday to 8 AM Monday local time).~~will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. ~~**M2.**~~ Each Responsible Entity will have as evidence of reporting an event~~,~~ to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-~~3~~4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted ~~within~~ by the later of 24 hours of recognition of meeting ~~the~~an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be~~ (4 ~~PM~~p.m. local time ~~on Friday to 8 AM Monday local time). (R2)~~will be considered the end of the business day).

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. ~~C.~~ Compliance

1. ~~1.~~ Compliance Monitoring Process

1.1. ~~1.1~~ Compliance Enforcement Authority:

~~The Regional Entity shall serve as the~~ "Compliance Enforcement Authority ~~(CEA) unless the applicable~~" means NERC or the Regional Entity, or any entity ~~is owned, operated, or controlled~~as otherwise designated by ~~the Regional Entity. In such cases the ERO~~ an Applicable Governmental Authority, in their respective roles of monitoring and/or ~~a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA~~enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~1.2~~ Evidence Retention:

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. ~~1.3~~ Compliance Monitoring and Enforcement ~~Processes:~~Program

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.4 Additional Compliance Information~~

~~None~~

~~Table of Compliance Elements~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VS
R1.	4. ~~Operations Planning~~	5. ~~Lower~~	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an ev reporting Opera Plan, but failed include four or applicable even types. OR The Responsible Entity failed to an event report Operating Plan.
R2.	6. ~~Operations Assessment~~	7. ~~Medium~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients ~~more than~~up to 24 hours ~~but less than or equal to 36 hours~~ after ~~meeting an event threshold~~the timing requirement	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~24 hours but less than or equal to 48 hours after ~~meeting an event threshold~~the timing	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~72 hours after ~~meeting an event threshold~~the timing	The Responsible Entity submitte event report (e. written or verba all required recipients more ~~60~~72 hours afte ~~meeting an eve threshold~~the tir requirement fo ~~reporting~~submi OR

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1

~~8. R3~~	~~9. Operations Planning~~	~~10. Medium~~	~~11. The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~12. OR~~ ~~13. The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~14. The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~15. OR~~ ~~16. The Responsible Entity validated 50% and less than 75% of the contact information contained in the~~	~~17. The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~18. OR~~ ~~19. The Responsible Entity validated 25% and less than 50% of the contact information contained in the~~	~~20. The Respo Entity valida all cor inform contai in the Opera Plan b was la three calend month more.~~ ~~21. OR~~ ~~22. The Respo Entity valida less th 25% o contac inform contai in the Opera Plan.~~

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Operating Plan.~~	~~Operating Plan.~~	

~~D.~~

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F. References~~

~~Guideline and Technical Basis (attached)~~

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written ~~Event Report~~event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

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Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in ~~actions~~action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a Facility.~~ ~~Do not report theft unless it degrades normal operation of a~~its Facility.
Physical threats to ~~a~~its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~its BES control center.
~~BES Emergency requiring public~~Public appeal for load reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~BA	Public appeal for load reduction ~~event~~to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~TOP	System-wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual firm load shedding~~	~~Initiating entity is responsible for reporting~~	~~Manual firm load shedding ≥ 100 MW.~~
Firm load sheddingresulting from a BES Emergency ~~resulting in automatic firm load shedding~~	~~DP,~~Initiating RC, BA, or TOP	~~Automatic firm~~Firm load shedding ≥ 100 MW (~~via~~manual or automatic ~~undervoltage or underfrequency load shedding schemes, or RAS~~).
~~Voltage~~BES Emergency resulting in voltage deviation on a Facility	TOP	~~Observed within its area a~~A voltage deviation of ~~±~~=/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
~~Loss~~Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	~~Loss~~Uncontrolled loss of firm load for ≥ 15 ~~Minutes:~~minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of: ≥ 2,000 MW ~~for entities~~ in the Eastern ~~or~~, Western ~~Interconnection~~ ~~OR~~ ~~≥ 1,000 MW for entities in the ERCOT~~ , or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES ~~Elements~~Facilities caused by a common disturbance (excluding successful automatic reclosing).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Unplanned evacuation of its BES control center ~~evacuation~~	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability affecting ~~a~~its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability ~~affecting a~~at its staffed BES control center for 30 continuous minutes or more ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~.

EOP-004 - Attachment 2: Event Reporting Form

<table>
<tr><th colspan="3">EOP-004 Attachment 2: Event Reporting Form
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net~~,~~ Facsimile 404-446-9770 or voice: 404-446-9780~~, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."~~</th></tr>
<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td>1.</td><td>Entity filing the report include:
Company name:
Name of contact person:
Email address of contact person:
Telephone Number:
Submitted by (name):</td><td></td></tr>
<tr><td>2.</td><td>Date and Time of recognized event.
Date: (mm/dd/yyyy)
Time: (hh:mm)
Time/Zone:</td><td></td></tr>
<tr><td>3.</td><td>Did the event originate in your system?</td><td>Yes ☐ No☐ Unknown ☐</td></tr>
<tr><td rowspan="2">4.</td><td colspan="2">Event Identification and Description:</td></tr>
<tr><td>(Check applicable box)
☐ Damage or destruction of a Facility
☐ Physical ~~T~~threat to ~~a~~its Facility
☐ Physical ~~T~~threat to ~~a~~its BES control center
☐ BES Emergency:
☐ firm load shedding
☐ public appeal for load reduction
☐ ~~s~~System-wide voltage reduction
~~☐ manual firm load shedding~~
~~☐ automatic firm load shedding~~
~~☐ Voltage~~ ☐ voltage deviation on a Facility
~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~
~~☐ Loss~~ ☐ uncontrolled loss of firm load
☐ System separation (islanding)
☐ Generation loss
☐ Complete loss of off-site power to a nuclear generating plant (grid supply)
☐ Transmission loss</td><td>Written description (optional):</td></tr>
</table>

EOP-004 Attachment 2: Event Reporting Form	
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net~~,~~ Facsimile 404-446-9770 or voice: 404-446-9780~~, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."~~	
Task	**Comments**
☐ ~~unplanned~~Unplanned evacuation of its BES control center ~~evacuation~~ ☐ Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	

Version History

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~**23.**~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**24. Data Gathering**~~

~~**25.** The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~Present expectations of the industry under CIP-001-1a:~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~Coordination of Local and State Law Enforcement Agencies with the FBI~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

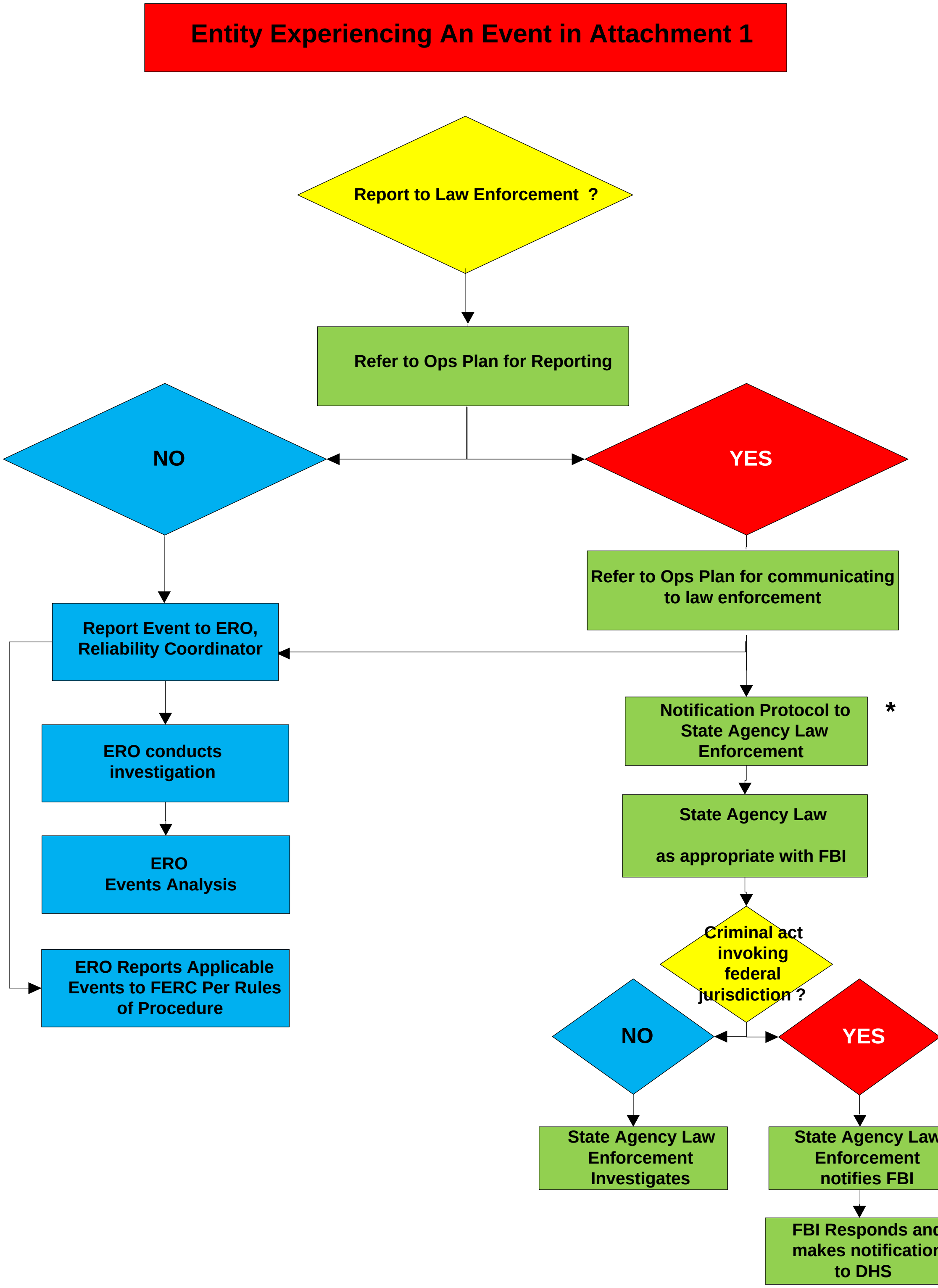
~~Coordination of Local and Provincial Law Enforcement Agencies with the RCMP~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~A Reporting Process Solution – EOP-004~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

~~Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts~~

~~Introduction~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.~~

~~The standards listed under the SAR are:~~

- ~~CIP-001 — Sabotage Reporting~~
- ~~EOP-004 — Disturbance Reporting~~

~~The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.~~

~~The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.~~

~~Summary of Concepts and Assumptions:~~

~~The Standard:~~

- ~~Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System~~
- ~~Provides clear criteria for reporting~~
- ~~Includes consistent reporting timelines~~
- ~~Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting~~
- ~~Provides clarity around of who will receive the information~~

~~*Discussion of Disturbance Reporting*~~

~~Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:~~

1. ~~An unplanned event that produces an abnormal system condition.~~
2. ~~Any perturbation to the electric system.~~
3. ~~The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.~~

~~Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

- ~~Bolts removed from transmission line structures~~
- ~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~
- ~~Destruction of Bulk Electric System equipment~~

~~*What about sabotage?*~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

~~Event analysis~~General situational awareness, correlation of data, ~~and~~ trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional ~~e~~Entities to report the incidents and provide ~~known~~ information known at the time of the report. Further data gathering necessary for ~~event~~ analysis is provided for under the ~~Events~~ERO Event Analysis Program and the NERC Rules of Procedure. ~~Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses.~~ The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~*Collection of Reportable Information or "One stop shopping"*~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

Rationale~~:~~

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT ~~approval~~adoption, the text from the rationale text boxes was moved to this section.

~~Rationale for R1:~~

~~The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.~~

~~Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective.~~

~~The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.~~

~~**Rationale for R2:**~~

~~Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

~~**Rationale for R3:**~~

~~Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.~~

~~**Rationale for EOP-004 Attachment 1:**~~

~~The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:~~

> ~~"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"~~

~~The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~2~~		~~Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.~~	~~Revision to entire standard (Project 2009-01)~~
~~2~~	~~November 7, 2012~~	~~Adopted by the NERC Board of Trustees~~	
~~2~~	~~June 20, 2013~~	~~FERC approved~~	
~~3~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~3~~	~~November 19, 2015~~	~~FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.~~	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

Where approval by an Applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

Where approval by an Applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-3, Measure M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.	EOP-004-4, Measure M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.	Updated standard version number. "…not limited to" removed from Measure M1, as unnecessary.
EOP-004-3, Requirement R2 **R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM	EOP-004-4, Requirement R2 **R2.** Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business	Requirement R2 revisions were provided for clarity; to remove the ambiguity for weekends and to add clarity for holidays.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
local time on Friday to 8 AM Monday local time).	day (4 p.m. local time will be considered the end of the business day).	
EOP-004-3, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)	EOP-004-4, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	Measure M2 was updated for clarity and to identify 4:00 p.m. local time to be considered as the end of the entity's business day.
EOP-004-3, Requirement R3	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.		004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.
EOP-004-3, Attachment 1 Event Type: Damage or destruction of a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action.	EOP-004-4, Attachment 1 Event Type: Damage or destruction of its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-3, Attachment 1	EOP-004-4, Attachment 1	The EOP SDT wanted to change the reporting responsibility to the Facility

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Event Type: Physical threats to a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	Event Type: Physical threats to its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.	owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
EOP-004-3, Attachment 1 Event Type: Physical threats to a BES control center Entity with Reporting Responsibility: RC, BA, TOP	EOP-004-4, Attachment 1 Event Type: Physical threats to its BES control center Entity with Reporting Responsibility: RC, BA, TOP	With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.	Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.	
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring public appeal for load reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Public appeal for load reduction event.	EOP-004-4, Attachment 1 Event Type: Public appeal for load reduction resulting from a BES Emergency Entity with Reporting Responsibility: BA Threshold for Reporting: Public appeal for load reduction to maintain continuity of the BES.	To maintain the continuity of the BES was added to better align with the DOE OE-417 reporting category. Rationale: The EOP SDT changed the reporting responsibility to the BA only based on the BA requirements in EOP-011-1 (FERC approved, pending enforcement) Requirement R2 “Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions;

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring system-wide voltage reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting. Threshold for Reporting: System wide voltage reduction of 3% or more.	EOP-004-4, Attachment 1 Event Type: System-wide voltage reduction resulting from a BES Emergency Entity with Reporting Responsibility: TOP Threshold for Reporting: System-wide voltage reduction of 3% or more.	The TOP is operating the system and is the only entity that would implement System-wide voltage reduction.
EOP-004-3, Attachment 1 Event Type: BES Emergency requiring manual firm load shedding Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Manual firm load shedding ≥ 100 MW.	EOP-004-4, Attachment 1 Event Type: Firm load shedding resulting from a BES Emergency Entity with Reporting Responsibility: Initiating RC, BA, or TOP Threshold for Reporting: Firm load shedding ≥ 100 MW (manual or automatic).	The RC, BA and TOP are the entities that would initiate manual firm load shedding.
EOP-004-3, Attachment 1 Event Type: BES Emergency resulting in automatic firm load shedding Entity with Reporting Responsibility: DP, TOP	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).		
EOP-004-3, Attachment 1 Event Type: Voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	EOP-004-4, Attachment 1 Event Type: BES Emergency resulting in voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.	To provide clarity to the Event Type and to the Threshold for Reporting, the language revisions were made.
EOP-004-3, Attachment 1 Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Entity with Reporting Responsibility: RC Threshold for Reporting: Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement. Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) are in the new standard TOP-001-3, Requirement R12 that becomes effective on 4/1/17, requiring a self-report if Tv is exceeded; the TOP-007-WECC-1 standard is pending retirement.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
for more than 30 minutes for Major WECC Transfer Paths (WECC only).		
EOP-004-3, Attachment 1 Event Type: Loss of firm load Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Loss of firm load for ≥ ≥ 300 MW for entities with previous yea 3,000 MW OR ≥ 200 MW for all other entities	EOP-004-4, Attachment 1 Event Type: Uncontrolled loss of firm load resulting from a BES Emergency Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities	To provide clarity to the Threshold for Reporting and to align with the DOE's OE-417 reporting category, language revisions were made.
EOP-004-3, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA, GOP Threshold for Reporting: Total generation loss, within one minute, of :	EOP-004-4, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA Threshold for Reporting: Total generation loss, within one minute, of:	The EOP SDT removed the reporting requirement from the GOPs to reduce redundant reporting. The BA should do the reporting given they have the generation status information.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection	Technical justification for reverting back to the value of 2,000 MW for the generation loss for the Québec Interconnection and for harmonizing with NERC EA process. 1. Generation in the Québec Interconnection is 95 % hydraulic. To be efficient, generation must operate within 80 % of its operating range. There is a large spinning reserve available at all times which aids in the recovery period after an event (ACE-Area Control Error). Historically, the recorded average ACE recovery time for a 2,000 MW loss is 5 minutes which is 3 times faster than the standard requirement of 15 minutes. <u>BAL-002-1a (R4.2)</u>. 2. Based on the Hydro Québec's generation loss reports, generation loss between 1,500 MW to 2,000 MW does not trig the first stage threshold of the UFLS scheme.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The frequency stayed above the underfrequency limit. 3. In order to maintain the integrity of the Québec system, the RPTC SPS in Québec (Generation Rejection and Remote Load Shedding) is designed to detect abnormal or predetermined system conditions, to take corrective actions and to deliberately remove up to 1,500 MW of preselected generation from the power system. Consequently, the system is design to remain stable upon the instantaneous loss of 1,500 MW of generation. For Hydro-Québec, a generation loss of more than 2,000 MW is considered as an issue, which is make sense with previous 2,000 MW generation loss reporting requirement. 4. The EEA Level 3 alert (EOP-002) in Québec is set generally set at 2,000 MW, based on the deficiency of

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operating reserves and margins. Up to now, no EEA Level 3 alert has occurred in the Québec Interconnection. 5. Hydro Québec's loss of generation in first contingency (n-1) is set around 2,000 MW. Technical justification for the value of 1,400 MW for the generation loss for the ERCOT Interconnection and for harmonizing with NERC EA process. 1. ERCOT maintains a mix of operating reserves (typically 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves) available at all times, which aids in the recovery period after an event affecting Area Control Error (ACE) or frequency. ERCOT typically procures between 2,300 MW to 3,000 MW of frequency responsive reserves for all

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operating hours besides procuring additional regulation and non-spinning reserves. The Load Resources controlled by Under-Frequency relay are set to respond automatically at 59.7 Hz to provide instantaneous frequency response. Historically, the recorded average ACE recovery time for a 1,400 MW loss is less than 10 minutes, which is much faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. The design criteria for ERCOT's frequency responsive reserves is to procure adequate reserves that allow frequency to stay above the under-frequency limit for up to ERCOT's resource contingency criteria limit of 2,750 MW. 3. The EEA level 1 alert (EOP-002) in ERCOT is set at 2,300 MW of Physical Responsive Capability (PRC) which is

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		a mix of operating reserves (typically 50% Load Resources and 50% frequency responsive spinning reserves).
EOP-004-3, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	EOP-004-4, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements	The Event Analysis Program (EAP) refers to loss of off-site power as “(LOOP)”. Therefore, LOOP has been added to the Threshold for Reporting to provide consistency.
EOP-004-3, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	EOP-004-4, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).	The definition of BES Element includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event Type. It could lead to confusion as to the element count for three elements contrary to design. In addition, the EAP uses the definition of “BES Facility” in its application, which could lead to additional confusion in evaluating a

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		reporting during an event. The EOP SDT revised "BES Elements" to "BES Facilities" to add clarity to the Threshold for Reporting and to align with the EAP language.
EOP-004-3, Attachment 1 Event Type: Unplanned BES control center evacuation Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	EOP-004-4, Attachment 1 Event Type: Unplanned evacuation of its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.	In the Threshold for Reporting, with the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…BES control center" to "…its BES control center."
EOP-004-3, Attachment 1 Event Type: Complete loss of voice communication capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of voice communication capability affecting a	EOP-004-4, Attachment 1 Event Type: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of Interpersonal Communication and	COM-001-2 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." And Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
BES control center for 30 continuous minutes or more.	Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.	not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.”
EOP-004-3, Attachment 1 Event Type: Complete loss of monitoring capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	EOP-004-4, Attachment 1 Event Type: Complete loss of monitoring or control capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.	The language revisions to this event type provides clarity to the Threshold for Reporting and better aligns with the EAP language.

Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
~~EOP-004-03~~EOP-004-3, ~~Requirement~~ Measure ~~R2~~M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.	~~EOP-004-04~~EOP-004-4, ~~Requirement R2~~Measure M1 **M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.	Updated standard version number. "…not limited to" removed from Measure M1, as unnecessary.
~~EOP-004-03~~EOP-004-3, Requirement R2 **R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM	~~EOP-004-04~~EOP-004-4, Requirement R2 **R2.** Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business	Requirement R2 revisions were ~~to~~ provided for clarity; to remove the ambiguity for weekends and to add clarity for holidays.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
local time on Friday to 8 AM Monday local time).	day (4 p.m. local time will be considered the end of the business day).	
EOP-004-3, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)	EOP-004-4, Measure M2 **M2.** Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	Measure M2 was updated for clarity and to identify 4:00 p.m. local time to be considered as the end of the entity's business day.
~~EOP-004-03~~EOP-004-3, Requirement R3	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.		004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Damage or destruction of a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Damage or destruction of its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.	The EOP SDT wanted to change the reporting responsibility to the Facility owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
~~EOP-004-03~~EOP-004-3, Attachment 1	~~EOP-004-04~~EOP-004-4, Attachment 1	The EOP SDT wanted to change the reporting responsibility to the Facility

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Event Type: Physical threats to a Facility Entity with Reporting Responsibility: BA, TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	Event Type: Physical threats to its Facility Entity with Reporting Responsibility: TO, TOP, GO, GOP, DP Threshold for Reporting: Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.	owner. It is the responsibility to the Facility owner, as the Threshold states. The EOP SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a Facility" to "…its Facility."
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Physical threats to a BES control center Entity with Reporting Responsibility: RC, BA, TOP	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Physical threats to its BES control center Entity with Reporting Responsibility: RC, BA, TOP	With the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…a BES control center" to "…its BES control center."

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.	Threshold for Reporting: Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.	
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: BES Emergency requiring public appeal for load reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: Public appeal for load reduction event.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Public appeal for load reduction resulting from a BES Emergency Entity with Reporting Responsibility: BA Threshold for Reporting: Public appeal for load reduction to maintain continuity of the BES.	To maintain the continuity of the BES was added to better align with the DOE OE-417 reporting category. Rationale: The EOP SDT changed the reporting responsibility to the BA only based on the BA requirements in EOP-011-1 (FERC approved, pending enforcement) Requirement R2 “Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions;

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: BES Emergency requiring system-wide voltage reduction Entity with Reporting Responsibility: Initiating entity is responsible for reporting Threshold for Reporting: System wide voltage reduction of 3% or more.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: System-wide voltage reduction resulting from a BES Emergency Entity with Reporting Responsibility: TOP Threshold for Reporting: System-wide voltage reduction of 3% or more~~ to maintain the continuity of the BES~~.	The TOP is operating the system and is the only entity that would implement ~~system~~System-wide voltage reduction.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: BES Emergency requiring manual firm load shedding Entity with Reporting Responsibility: Initiating entity is responsible for reporting. Threshold for Reporting: Manual firm load shedding ≥ 100 MW.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Firm load shedding resulting from a BES Emergency Entity with Reporting Responsibility: Initiating RC, BA, or TOP Threshold for Reporting: Firm load shedding ≥ 100 MW (manual or automatic).	The RC, BA and TOP are the entities that would initiate manual firm load shedding.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: BES Emergency resulting in automatic firm load shedding Entity with Reporting Responsibility: DP, TOP	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting has been merged with Event Type: Firm load shedding resulting from a BES Emergency.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Threshold for Reporting: Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).		
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: BES Emergency resulting in voltage deviation on a Facility Entity with Reporting Responsibility: TOP Threshold for Reporting: A voltage deviation of =/> ~~±~~ 10% of nominal voltage sustained for ≥ 15 continuous minutes.	To provide clarity to the Event Type and to the Threshold for Reporting, the language revisions were made.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Entity with Reporting Responsibility: RC Threshold for Reporting: Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement.	This Event Type/Entity with Reporting Responsibility/Threshold for Reporting is proposed for retirement. Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) are in the new standard TOP-001-3, Requirement R12 that becomes effective on 4/1/17, requiring a self-report if Tv is exceeded; the TOP-007-WECC-1 standard is pending retirement.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
for more than 30 minutes for Major WECC Transfer Paths (WECC only).		
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Loss of firm load Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Loss of firm load for ≥ ≥ 300 MW for entities with previous yea 3,000 MW OR ≥ 200 MW for all other entities	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Uncontrolled loss of firm load resulting from a BES Emergency Entity with Reporting Responsibility: BA, TOP, DP Threshold for Reporting: Uncontrolled loss of firm load for ≥ 15 ~~Minutes~~ minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities	To provide clarity to the Threshold for Reporting and to align with the DOE's OE-417 reporting category, language revisions were made.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA, GOP Threshold for Reporting: Total generation loss, within one minute, of :	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Generation loss Entity with Reporting Responsibility: BA Threshold for Reporting: Total generation loss, within one minute, of:	The EOP SDT removed the reporting requirement from the GOPs to reduce redundant reporting. The BA should do the reporting given they have the generation status information.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection	Technical justification for reverting back to the value of 2,000 MW for the generation loss for the Québec Interconnection and for harmonizing with NERC EA process. 1. Generation in the Québec Interconnection is 95 % hydraulic. To be efficient, generation must operate within 80 % of its operating range. There is a large spinning reserve available at all times which aids in the recovery period after an event (ACE-Area Control Error). Historically, the recorded average ACE recovery time for a 2,000 MW loss is 5 minutes which is 3 times faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. Based on the Hydro Québec's generation loss reports, generation loss between 1,500 MW to 2,000 MW does not trig the first stage threshold of the UFLS scheme.

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		The frequency stayed above the underfrequency limit. 3. In order to maintain the integrity of the Québec system, the RPTC SPS in Québec (Generation Rejection and Remote Load Shedding) is designed to detect abnormal or predetermined system conditions, to take corrective actions and to deliberately remove up to 1,500 MW of preselected generation from the power system. Consequently, the system is design to remain stable upon the instantaneous loss of 1,500 MW of generation. For Hydro-Québec, a generation loss of more than 2,000 MW is considered as an issue, which is make sense with previous 2,000 MW generation loss reporting requirement. 4. The EEA Level 3 alert (EOP-002) in Québec is set generally set at 2,000 MW, based on the deficiency of

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		operating reserves and margins. Up to now, no EEA Level 3 alert has occurred in the Québec Interconnection. 5. Hydro Québec's loss of generation in first contingency (n-1) is set around 2,000 MW. Technical justification for ~~reverting back to~~ the value of ~~2~~1,~~000~~ 400 MW for the generation loss for the ~~Québec~~ ERCOT Interconnection and for harmonizing with NERC EA process. 1. ERCOT maintains a mix of operating reserves (typically 50% Load Resources controlled by under-frequency relays and 50% frequency responsive spinning reserves) available at all times, which aids in the recovery period after an event affecting Area Control Error (ACE) or frequency. ERCOT typically procures between 2,300 MW to 3,000 MW of

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		frequency responsive reserves for all operating hours besides procuring additional regulation and non-spinning reserves. The Load Resources controlled by Under-Frequency relay are set to respond automatically at 59.7 Hz to provide instantaneous frequency response. Historically, the recorded average ACE recovery time for a 1,400 MW loss is less than 10 minutes, which is much faster than the standard requirement of 15 minutes. BAL-002-1a (R4.2). 2. The design criteria for ERCOT's frequency responsive reserves is to procure adequate reserves that allow frequency to stay above the under-frequency limit for up to ERCOT's resource contingency criteria limit of 2,750 MW. 3. The EEA level 1 alert (EOP-002) in ERCOT is set at 2,300 MW of Physical

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Responsive Capability (PRC) which is a mix of operating reserves (typically 50% Load Resources and 50% frequency responsive spinning reserves).
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Complete loss of off-site power to a nuclear generating plant (grid supply) Entity with Reporting Responsibility: TO, TOP Threshold for Reporting: Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements	The Event Analysis Program (EAP) refers to loss of off-site power as "(LOOP)". Therefore, LOOP has been added to the Threshold for Reporting to provide consistency.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Transmission loss Entity with Reporting Responsibility: TOP Threshold for Reporting: Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common	The definition of BES Element includes generation. The reporting requirement for this Event Type is the TOP. The TOP does not have the visibility to report for the GO and/or the GOP for this Event Type. It could lead to confusion as to the element count for three elements contrary to design. In addition, the EAP uses the definition of "BES Facility" in its application, which could lead

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
disturbance (excluding successful automatic reclosing).	disturbance (excluding successful automatic reclosing).	to additional confusion in evaluating a reporting during an event. The EOP SDT revised "BES Elements" to "BES Facilities" to add clarity to the Threshold for Reporting and to align with the EAP language.
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Unplanned BES control center evacuation Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Unplanned evacuation of its BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.	In the Threshold for Reporting, with the specific entities listed for reporting, the event type and reporting entity better aligns with the word change from "…BES control center" to "…its BES control center."
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Complete loss of voice communication capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of voice communication capability affecting a	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP	COM-001-2 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." And Alternative Interpersonal Communication as:

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
BES control center for 30 continuous minutes or more.	Threshold for Reporting: Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.	"Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."
~~EOP-004-03~~EOP-004-3, Attachment 1 Event Type: Complete loss of monitoring capability Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	~~EOP-004-04~~EOP-004-4, Attachment 1 Event Type: Complete loss of monitoring or control capability at its staffed BES control center Entity with Reporting Responsibility: RC, BA, TOP Threshold for Reporting: Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.	The language revisions to this event type provides clarity to the Threshold for Reporting and better aligns with the EAP language.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were slightly revised to add "event reporting." The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their event reporting Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their event reporting Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels
VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were slightly revised to add "event reporting." The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their event reporting Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their event reporting Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal~~more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.~~,~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~ 24 hours but less than or equal to 48 hours after the timing requirement for submittal~~recognition of meeting an event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.~~,~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~ 72 hours after the timing requirement for submittal~~recognition of meeting an event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.~~,~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~60~~ 72 hours after the timing requirement for submittal~~recognition of meeting an event threshold for reporting~~. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.~~,~~ OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement

Project 2015-08 Emergency Operations
EOP-004-4

Final Ballot Open through February 2, 2017

Now Available

A final ballot for **EOP-004-4 – Event Reporting** is open through **8 p.m. Eastern, Friday, December 9, 2016**.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2015-08 Emergency Operations | EOP-004-4 EOP-004-4 FN 3 ST
Voting Start Date: 1/24/2017 9:15:48 AM
Voting End Date: 2/2/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 288
Total Ballot Pool: 340
Quorum: 84.71
Weighted Segment Value: 93.8

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	70	0.946	4	0.054	0	2	13
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	75	1	52	0.912	5	0.088	0	2	16
Segment: 4	23	1	20	1	0	0	0	0	3
Segment: 5	84	1	65	0.915	6	0.085	0	0	13
Segment: 6	45	1	38	0.905	4	0.095	0	0	3
Segment: 7	3	0.1	1	0.1	0	0	0	1	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.7	7	0.7	0	0	0	1	1
Totals:	340	6.8	262	6.378	20	0.422	0	6	52

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Lauren Price		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Abstain	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Aaron Austin		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Dehn Stevens		None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Chris Gowder	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Lakeland Electric	David Hadzima		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Calpine Corporation	Hamid Zakery		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Empire District Electric Co.	Michael kidwell		None	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		None	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer	Tim Womack	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

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10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 340 of 340 entries

Exhibit H

Standards Drafting Team Roster

Standard Drafting Team Roster

Project 2015-08 Emergency Operations

	Participant	Entity
Chair	Connie Lowe	Dominion Resources Services, Inc.
Vice Chair	Robert Staton	Xcel Energy
Members	Karen Backman	IESO
	Matthew Beilfuss	WEC Energy Group
	Richard Cobb	MISO
	Bobby Crump	Luminant Generation Co., LLC
	Jon Langford	Southwest Power Pool
	Ali Miremadi	California Independent System Operator
	Jack Thomas	PJM Interconnection
	Walter Ullrich	Great River Energy
PMOS Liaison	Ken Goldsmith	Alliant Energy
NERC Staff	Laura Anderson – Standards Developer	North American Electric Reliability Corporation
	Nina Johnston – Senior Counsel	North American Electric Reliability Corporation