NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

April 3, 2017

VIA ELECTRONIC FILING

David Erickson
President and Chief Executive Officer
Alberta Electric System Operator
2500, 330 - 5 Avenue SW
Calgary, Alberta
T2P 0L4

RE: *North American Electric Reliability Corporation*

Dear Mr. Erickson:

The North American Electric Reliability Corporation hereby submits Notice of Filing of the North American Electric Reliability Corporation of Proposed Emergency Operations Reliability Standards. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to this filing.

NERC understands the AESO may adopt the proposed reliability standards subject to Alberta legislation, principally as established in the *Transmission Regulation* ("the T Reg."). Briefly, it is NERC's understanding that the T Reg. requires the following with regard to the adoption in Alberta of a NERC Reliability Standard:

1. The AESO must consult with those market participants that it considers are likely to be directly affected.

2. The AESO must forward the proposed reliability standards to the Alberta Utilities Commission for review, along with the AESO's recommendation that the Commission approve or reject them.

3. The Commission must follow the recommendation of the AESO that the Commission approve or reject the proposed reliability standards unless an interested person satisfies the Commission that the AESO's recommendation is "technically deficient" or "not in the public interest."

Further, NERC has been advised by the AESO that the AESO practice with respect to the adoption of a NERC Reliability Standard includes a review of the NERC Reliability Standard for applicability to Alberta legislation and electric industry practice. NERC has been advised that, while the objective is to adhere as closely as possible to the requirements of the NERC Reliability Standard, each NERC Reliability Standard approved in Alberta (called an "Alberta reliability standard") generally varies from the similar and related NERC Reliability Standard.

NERC requests the AESO consider the Proposed Emergency Operations Reliability Standards in the filing for adoption in Alberta as an "Alberta reliability standard(s)," subject to the required procedures and legislation of Alberta.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Shamai Elstein

Shamai Elstein
Senior Counsel for the North American Electric Reliability Corporation

Enclosure

BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED EMERGENCY OPERATIONS RELIABILITY STANDARDS

Nina H. Jenkins-Johnston
Senior Counsel
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-9650
nina.johnston@nerc.net

Counsel for the North American Electric Reliability Corporation

April 3, 2017

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BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED EMERGENCY OPERATIONS RELIABILITY STANDARDS

The North American Electric Reliability Corporation ("NERC") hereby submits 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*). The proposed Reliability Standards (**Exhibit A**) are just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also provides notice of: (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 current Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2, and EOP-008-1.

This filing presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the proposed Reliability Standards meet the Reliabilithy Standards criteria (**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").[1] They also reflect collaboration with the United States Department of Energy ("DOE") to eliminate 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, the proposed Reliability Standards and the proposed retirement of Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2 and EOP-008-1 are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[1] 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.

II. NOTICES AND COMMUNICATIONS

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

Nina Jenkins-Johnston
Senior Counsel
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-9650
nina.johnston@nerc.net

Howard Gugel
Director of Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
howard.gugel@nerc.net

III. BACKGROUND

A. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Reliability Standard development process. NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[2] 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, and thus satisfy certain of the criteria for approving Reliability Standards. 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 applicable governmental authorities.

B. 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

[2] 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.

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 standards; (2) apply Paragraph 81 criteria;[3] while making the standards more results-based; and (3) address the Federal Energy Regulatory Commission's ("FERC") concern articulated in Order No. 749 regarding system restoration training.[4]

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

IV. JUSTIFICATION

As discussed in detail in **Exhibit C**, the proposed Reliability Standards satisfy the Reliability Standards criteria and are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[3] *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).

[4] 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.

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.

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 current 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.[5] The process of validating contact lists is a good business practice of many utilities, but not a reliability priority. Furthermore,

[5] 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.

this proposed retirement of Requirement R3 is also consistent with the Panel's recommendation and rationale.

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 current 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.[6] 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

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[6] 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.

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 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 <u>a</u> Facility" to "Damage or destruction of <u>its</u> 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 <u>its</u> 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 "<u>It is not necessary</u> 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 <u>its BES control center" and the threshold to "Suspicious device or activity at its</u> 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 current 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 current 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,[7] 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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[7] 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 current 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 ≥ 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 current "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).[8] 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

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8 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 current 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 current 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. On May 29, 2014, NERC submitted 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."[9] 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~~."

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

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9 *Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standards COM-001-2 and COM-002-4*, (filed May 29, 2014).

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

On March 19, 2013, NERC submitted a proposal with this authority for the retirement of Requirement R3, Part 3.1, and Requirement R3 was retired by FERC in Order No. 788.[10] NERC is not proposing any further revisions to Requirement R3 in this filing.

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"),[11] 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,

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

11 *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.

which is no less than 30 calendar days after identifying the modification. Proposed Requirement R4 provides as follows:

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 current 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*.[12] 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.

[12] 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.

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 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.[13] In the current 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

[13] FERC-NERC Joint Report at 37.

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 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 current 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 current 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. Current 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 current 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~~ <u>its</u> 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)

<u>8.5. Transition to Balancing Authority for Demand and resource balance within its area.</u>

j. EOP-005-3, Proposed Requirement R9

Proposed Requirement R9 renumbers language from current 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 FERC approved several System Restoration Reliability Standards, FERC 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."[14] The EOP SDT

[14] Order No. 749 at P 24.

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 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~~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.

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~~ 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.

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 current 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 current 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 current 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 current 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. FERC adopted the term in Order No. 817, which approved revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards.[15] 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

[15] 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). These proposed standards had been submitted to this authority on March 25, 2015.

FERC 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.

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.

V. EFFECTIVE DATE

Proposed Reliability Standards EOP-004-4, EOP-005-3, EOP-006-3, and EOP-008-2 shall become effective as set forth in the proposed Implementation Plans, provided in Exhibit B hereto. The proposed Implementation Plans provide that where approval by an applicable governmental authority is required, the standards 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 standards, or as otherwise provided for by the applicable governmental authority. Where approval by an applicable governmental authority is not required, the standards shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston
Senior Counsel
Shamai Elstein
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
nina.johnston@nerc.net
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

April 3, 2017

EXHIBITS A-B AND D-H

Reliability Standards Criteria

The discussion below explains how the proposed Reliability Standard has met or exceeded the Reliability Standards 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.**

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 FERC directive from Order No. 749.

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.**

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply. 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.**

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for each of the proposed Reliability Standards comport with NERC and FERC 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 similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences.

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.

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.

The proposed Reliability Standards achieve the reliability goals effectively and efficiently. Consistent with a FERC 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.

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.**

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.**

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.**

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.

9. The implementation time for the proposed Reliability Standard is reasonable.

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 Reliability Standard development process.

The proposed Reliability Standards were developed in accordance with NERC's ANSI-accredited processes for developing and approving Reliability Standards.[1] **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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1 *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.

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.

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.