NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

March 25, 2015

VIA ELECTRONIC FILING

Ms. Erica Hamilton, Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
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RE: *North American Electric Reliability Corporation*

Dear Ms. Hamilton:

The North American Electric Reliability Corporation ("NERC") hereby submits Notice of Filing of the North American Electric Reliability Corporation of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to this filing.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins

Holly A. Hawkins
Associate General Counsel for the North American Electric Reliability Corporation

Enclosure

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BEFORE THE
BRITISH COLUMBIA UTILITIES COMMISSION
OF THE PROVINCE OF BRITISH COLUMBIA

NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED TRANSMISSION OPERATIONS AND INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS

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March 25, 2015

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BRITISH COLUMBIA UTILITIES COMMISSION
OF THE PROVINCE OF BRITISH COLUMBIA

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NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED TRANSMISSION OPERATIONS AND INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS

The North American Electric Reliability Corporation ("NERC") hereby submits the following nine proposed Reliability Standards (Exhibit A):[1]

- TOP-001-3 (Transmission Operations);
- TOP-002-4 (Operations Planning);
- TOP-003-3 (Operational Reliability Data);
- IRO-001-4 (Reliability Coordination – Responsibilities);
- IRO-002-4 (Reliability Coordination –Monitoring and Analysis);
- IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-2 (Reliability Coordinator Data Specification and Collection);
- IRO-014-3 (Coordination Among Reliability Coordinators); and
- IRO-017-1 (Outage Coordination).

The proposed Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed further below, the proposed Reliability Standards replace the Reliability Standards previously submitted on April 30, 2013 and May 14, 2013 (the "Pending TOP/IRO Standards).[2]

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

2 Concurrent with this filing, NERC is submitting a notice to withdraw the following Reliability Standards previously submitted: (1) proposed revisions to Reliability Standard TOP-006-3 to divide the reporting

NERC also provides notice of: (i) revised definitions for the NERC Glossary terms "Operational Planning Analysis" and "Real-time Assessment" (Exhibit A); (ii) the Implementation Plan for the proposed Reliability Standards and definitions (Exhibit B); and (iii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and J). Finally, NERC provides notice of retirement of the following Reliability Standards.

- IRO-001-1.1 (Reliability Coordination – Responsibilities and Authorities);
- IRO-002-2 (Reliability Coordination — Facilities)
- IRO-003-2 (Reliability Coordination – Wide-Area View);
- IRO-004-2 (Reliability Coordination – Operations Planning);
- IRO-005-3.1a (Reliability Coordination – Current Day Operations);
- IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-1a (Reliability Coordinator Data Specification and Collection);
- IRO-014-1 (Coordination Among Reliability Coordinators);
- IRO-015-1 (Notifications and Information Exchange Between Reliability Coordinators);
- IRO-016-1 (Coordination of Real-time Activities Between Reliability Coordinators);
- PER-001-0.2 (Operating Personnel Responsibility and Authority);
- TOP-001-1a (Reliability Responsibilities and Authorities);
- TOP-002-2.1b (Normal Operations Planning);
- TOP-003-1 (Planned Outage Coordination);
- TOP-004-2 (Transmission Operations);
- TOP-005-2a (Operational Reliability Information);
- TOP-006-2 (Monitoring System Conditions);
- TOP-007-0 (Reporting System Operating Limit and Interconnection Reliability Operating Limit Violations); and
- TOP-008-1 (Response to Transmission Limit Violations).

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responsibilities of Balancing Authorities and Transmission Operators into separate requirements; (2) three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection and Control ("PRC") Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards; and (3) four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators).

This filing presents the technical basis and purpose of the proposed Reliability Standards and definitions, a summary of the development history (Exhibit K), and a demonstration that the proposed Reliability Standards meet the Reliability Standards criteria (Exhibit C).

This filing is organized as follows: Section I of the filing presents an executive summary of the proposed Reliability Standards. Section II of the filing provides the individuals to whom notices and communications related to the filing should be provided. Section III provides information on the development of the proposed Reliability Standards. Section IV of the filing then discusses the proposed Reliability Standards and definitions in detail, including the purpose and improvements of the proposed Reliability Standards and definitions. Section IV also explains how the proposed Reliability Standards address:

- the recommendations in the joint Federal Energy Regulatory Commission ("FERC") and NERC report on the 2011 Arizona-Southern California outages ("Southwest Outage Report") (*see also* Exhibit F),[3]
- concerns raised by the FERC in the November 21, 2013 *Notice of Proposed Rulemaking*, which proposed to remand the Pending TOP/IRO Standards (the "TOP/IRO NOPR") (*see also* Exhibit G),[4] and
- outstanding FERC directives related to the proposed Reliability Standards (*see also* Exhibit H).

I. EXECUTIVE SUMMARY

The proposed Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards address matters that are fundamental to grid reliability as they pertain to the coordinated efforts to plan and operate the Bulk Electric

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[3] FERC and NERC, *Arizona-Southern California Outage on September 8, 2011, Causes and Recommendations* (Apr. 27, 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[4] *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013) ("TOP/IRO NOPR").

System in a reliable manner under both normal and abnormal conditions. As discussed further below, the proposed Reliability Standards consolidate many of the currently effective TOP and IRO Reliability Standards and replace the Pending TOP/IRO Standards in addressing the roles and responsibilities of Reliability Coordinators, Transmission Operators and Balancing Authorities with respect to planning and operating the Bulk Electric System. The proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the Bulk Electric System is operated within pre-established limits while enhancing situational awareness and strengthening operations planning.

The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. Among other things, the proposed Reliability Standards help to ensure that Reliability Coordinators and Transmission Operators work together, and with other functional entities, to operate the Bulk Electric System within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"). SOLs and IROLs are vital concepts in NERC's Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of Transmission Operators, although certain requirements apply to the roles and responsibilities of the Balancing Authority. The proposed IRO Reliability Standards set forth the responsibility and authority of Reliability Coordinators to provide for reliable operations. Reliability Coordinators have an essential role in ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the Bulk Electric System.

The proposed Reliability Standards improve upon the currently effective TOP and IRO Reliability Standards by eliminating gaps, ambiguities, and redundancies, and by improving the overall quality of the TOP and IRO Reliability Standards. Specifically, the proposed Reliability Standards include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

II. NOTICES AND COMMUNICATIONS

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

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III. BACKGROUND

A. NERC Reliability Standards Development Procedure

The proposed Reliability Standards and definitions 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.[5] 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 satisfies 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 stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits a proposed Reliability Standard to the applicable governmental authoritites for approval.

B. FERC Proceeding History

As noted above, the proposed Reliability Standards are intended to replace the Pending TOP/IRO Standards, which consist of the following:

- *Reliability Standard TOP-006-3 (Monitoring System Conditions)*, which NERC submitted on April 30, 2013. The proposed revisions to Reliability Standard TOP-006-3 were intended to divide the reporting responsibilities of Balancing Authorities and Transmission Operators into separate requirements.
- *Reliability Standards TOP-001-2 (Transmission Operations), TOP-002-3* (*Operations Planning), TOP-003-2 (Operational Reliability Data) and PRC-001-2 (System Protection Coordination)*, which NERC submitted on May 14, 2013. These Reliability Standards were intended to replace the eight currently effective TOP Reliability Standards.[6]
- *Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators)*, which NERC submitted on May 14, 2013. These four Reliability Standards were intended to replace six currently effective IRO Reliability

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5 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

6 The changes in proposed Reliability Standard PRC-001-2 were administrative in nature and limited to removal of three requirements in currently effective Reliability Standard PRC-001-1 that were addressed in proposed Reliability Standard TOP-003-2. Concurrent with this filing, NERC is providing notice of withdrawal of PRC-001-2 but is not proposing herein any changes to that standard. Any changes corresponding changes to PRC-001 are being addressed in Project 2007-06.2 – Phase 2 of System Protection Coordination.

Standards (IRO-001-1.1, IRO-002-2, IRO-005-3a, IRO-014-1, IRO-015-1, and IRO-016-1).

On November 21, 2013, FERC issued the TOP/IRO NOPR, proposing to approve proposed Reliability Standard TOP-006-3 but remand the other Pending TOP/IRO Standards. A summary of FERC's concerns raised in the TOP/IRO NOPR are included in Section IV as well as Exhibit G.

C. Project 2014-03 – Revisions to TOP and IRO Standards

In response to the TOP/IRO NOPR and consistent with NERC's responsibility as the ERO to develop Reliability Standards that provide for an adequate level of reliability of the Bulk-Power System, NERC, with FERC and industry support, initiated Project 2014-03 to develop revisions to the Pending TOP/IRO Reliability Standards and fulfill the goals of the original projects: Project 2006-06 Reliability Coordination[7] and Project 2007-03 Real-time Operations.[8] The objective of Project 2014-03 was to provide clear, unambiguous Reliability Standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities operate the interconnected transmission system in a safe and reliable manner. In addition, the Project 2014-03 standard drafting team considered recommendations from the Independent Experts Review Panel ("IERP").[9]

As discussed below, the proposed Reliability Standards reflect an improved, more robust set of Reliability Standards. The NERC Board adopted the proposed Reliability Standards and

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7 The Project 2006-06 development webpage is available at http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx.

8 The Project 2007-03 development webpage is available at http://www.nerc.com/pa/Stand/Pages/Real-time_Operations_Project_2007-03.aspx.

9 In 2013, NERC formed the IERP, which consisted of five industry experts, to independently review the NERC Reliability Standards to assess the content and quality of the Reliability Standards, including the identification of Bulk-Power System risks. The IERP's final report (the "IERP Report") is available at : http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

definitions on November 13, 2014, with the exception of proposed Reliability Standard TOP-001-3, which the Board adopted on February 12, 2015.

IV. JUSTIFICATION

As discussed in Exhibit C, the proposed Reliability Standards and definitions satisfy the Reliability Standards criteria and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The development of the proposed Reliability Standards was informed by recent industry reports and initiatives, including two NERC-sponsored technical conferences in March 2014,[10] the Southwest Outage Report, the IERP Report, the NERC Operating Committee consideration of the IERP report (Exhibit I), and FERC's TOP/IRO NOPR.

The following section provides: (1) an explanation of the purpose and improvements in the proposed Reliability Standards and modified NERC Glossary definitions; (2) a description of each of the proposed definitions and requirements in the proposed Reliability Standards; and (3) an explanation of the manner in which the proposed Reliability Standards address the recommendations in the Southwest Outage Report, the concerns raised in the TOP/IRO NOPR, and outstanding FERC directives related to the proposed Reliability Standards.

A. Purpose of and Improvements in the Proposed Reliability Standards

1. Purpose

The proposed Reliability Standards address the important reliability goal of setting forth the requirements applicable to Reliability Coordinators, Transmission Operators, and Balancing Authorities with respect to planning and operating the Bulk-Power System, including requirements for operating the interconnected transmission system within predetermined

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[10] The slides from the conferences are available at: http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/top_iro_technical_conference_presentation_20140306.pdf.

operating limits. The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The proposed Reliability Standards consolidate the currently effective TOP and IRO Reliability Standards, providing a more precise set of Reliability Standards addressing operating responsibilities. The mapping document, provided as Exhibit D hereto, shows how the currently effective Reliability Standards map to the proposed Reliability Standards.

The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of Transmission Operators. Among other things, the proposed revisions to the TOP Reliability Standards help ensure that Transmission Operators plan to operate within all SOLs.

The proposed IRO Reliability Standards, which complement the proposed TOP Standards, are designed to ensure that the Bulk Electric System is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions. The proposed IRO Reliability Standards set forth the responsibility and authority of Reliability Coordinators to provide for reliable operations. Reliability Coordinators have an essential role in ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the Bulk Electric System.

2. Improvements

The proposed Reliability Standards improve upon the currently effective TOP and IRO Reliability Standards by eliminating gaps, ambiguities, and redundancies, and by improving the overall quality of the TOP and IRO Reliability Standards. Specifically, the proposed Reliability Standards include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

a) Operating Within SOLs and IROLs

An SOL is defined in the NERC Glossary as:

> The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
>
> - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
> - Transient Stability Ratings (Applicable pre- and post- Contingency Stability Limits)
> - Voltage Stability Ratings (Applicable pre- and post- Contingency Voltage Stability)
> - System Voltage Limits (Applicable pre- and post- Contingency Voltage Limits)"

An IROL is defined as:

> A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

As FERC has noted, during deteriorating system conditions, an SOL can rapidly degrade into an IROL.[11] When any Facility Rating or Stability Limit is exceeded, or expected to be exceeded, these conditions should be mitigated to avoid the possibility of further deteriorating system conditions and the potential for a Cascading event.

The proposed Reliability Standards improve upon existing obligations for Transmission Operators and Reliability Coordinators to help ensure the Bulk Electric System is operated

[11] TOP/IRO NOPR at P 52.

within predetermined operating limits. Specifically, SOLs, which must be monitored by Transmission Operators, include Ratings and limits necessary to ensure reliable operation within acceptable reliability criteria, as determined pursuant to Facilities Design, Connections and Maintenance ("FAC") Reliability Standards. In the proposed IRO Reliability Standards, Reliability Coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require the Reliability Coordinator to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.[12]

When a Transmission Operator or Reliability Coordinator, based on its analysis and monitoring of SOLs and/or IROLs, identify a violation of operating limits, the proposed TOP and IRO Reliability Standards set forth the requirements for applicable entities to resolve the situation within specified timeframes. Specifically, proposed Reliability Standard TOP-001-3 requires that all violations of IROLs be resolved within the IROL T_V,[13] which is a technically-based performance expectation that essentially provides that IROL violations cannot exceed 30 minutes, which is consistent with the 30-minute criteria contained in existing TOP Reliability Standards. This proposed revision provides consistency with the Reliability Coordinator requirements contained in currently effective Reliability Standard IRO-009-1. The proposed Reliability Standards also include revisions that will require resolution of SOL violations within

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12 *See* id. As FERC noted, "[d]uring deteriorating system conditions, an SOL can rapidly degrade into an IROL.... Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded." *Id.*

13 IROL T_v is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "[t]he maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes."

specified timeframes that are based on Ratings methodologies developed pursuant to the FAC Reliability Standards and coordinated between the Transmission Operator and Reliability Coordinator.

b) Improved Definitions

The proposed Reliability Standards also use certain foundational NERC Glossary terms, the definitions for which have been improved as part of Project 2014-03. Specifically, NERC is proposing revised definitions for "Operational Planning Analysis" and "Real-time Assessment." As described below, the proposed definitions provide significant additional detail over the currently effective definitions to enhance the consistency and the reliability benefit of Operational Planning Analyses and Real-time Assessments. For example, the proposed definition of Real-time Assessment includes several inputs that were identified as contributing to past outages on the Bulk Electric System, which, in turn, will enhance situational awareness.[14]

Additionally, the proposed Reliability Standards now use the proposed NERC Glossary term "Operating Instruction"[15] instead of the term "reliability directive." The proposed NERC Glossary term "Operating Instruction" defines the scope of commands that are covered by the proposed TOP and IRO Reliability Standards.

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14 The proposed definition of Real-time Assessment is "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)" Several inputs are based on the Southwest Outage Report recommendations as described in Exhibit F.

15 The defined term "Operating Instruction" was developed along with proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocol) and was submitted on May 29, 2014. On September 18, 2014, FERC issued a Notice of Proposed Rulemaking proposing to adopt the proposed Reliability Standards and new proposed definitions (including Operating Instruction), as well as the implementation plans, VRFs, and VSLs for the proposed Reliability Standards.

c) *Situational Awareness*

The proposed Reliability Standards also improve upon existing situational awareness requirements. Collectively, the revised definition of Real-time Assessment and associated requirements for Real-time monitoring and Real-time Assessments in proposed Reliability Standards TOP-001-3 and IRO-008-2 provide for consistency in the operations of the Transmission Operator and Reliability Coordinator, giving clear definition of responsibilities and avoiding potential gaps. For example, the proposed TOP Reliability Standards include a requirement for Transmission Operators to perform Real-time Assessments at least once every 30 minutes. The requirement for Transmission Operators to assess system operating conditions on a frequent basis, which is analogous to an existing requirement in the currently effective IRO Reliability Standards requiring Reliability Coordinators to perform Real-time Assessments, will improve situational awareness and reinforce the responsibilities outlined in the NERC Functional Model.[16] As noted above, the definition of Real-time Assessments has been modified to include additional inputs to improve situational awareness.

The proposed TOP Reliability Standards also include clear requirements for monitoring system conditions that support completion of Real-time Assessments and align with similar requirements in the currently effective IRO Reliability Standards. Specifically, proposed Reliability Standard TOP-001-3 requires, among other things, Transmission Operators and Balancing Authorities to monitor Facilities and status indications necessary to operate within SOLs and support Interconnection frequency.

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[16] NERC Functional Model at page 38. The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes.

d) Operations Planning and Outage Coordination

The proposed Reliability Standards also improve upon operational planning requirements for Reliability Coordinators and Transmission Operators. Proposed Reliability Standards IRO-008-2 and TOP-002-4 contain requirements for performing day-ahead studies and developing plans to operate within operating limits. Certain operational planning requirements are applicable to the Balancing Authorities as well, as discussed below. Further, the revised definition for Operational Planning Analysis incorporates recommendations from the Southwest Outage Report that are designed to address operations planning shortfalls with the potential to cause repeat occurrences of similar events, as further described in Exhibit F. For example, the revised definition of Operational Planning Analysis includes use of external system data such as transmission or generation outages, interchange prediction, and projected system conditions to improve the scope, accuracy, and quality of the analysis.

Operations planning relies on timely and accurate information of transmission and generation outages. Consequently, the standard drafting team developed proposed Reliability Standard IRO-017-1 to address the coordination of outages in advance. Proposed Reliability Standard IRO-017-1 establishes operational planning requirements for each Reliability Coordinator to implement an outage coordination process for its area that will identify and resolve issues with the potential to impact reliable operations. Proposed Reliability Standard IRO-017-1 thus addresses a reliability gap identified in the IERP Report and the Southwest Outage Report.

e) Operational Reliability Data

The proposed Reliability Standards establish clear requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations. Effective operations planning and accurate assessment of system conditions in real-time rely on complete, current, and timely data and information. Specifically, proposed TOP-003-1 establishes requirements for Transmission Operators and Balancing Authorities to specify the data and information needed to perform their reliability functions, and obligates entities to provide the data according to prescribed formats and protocols. In doing so, proposed TOP-003-1 is applying the approach used for Reliability Coordinators in IRO-010-1a to improve the flow of operational reliability data needed by Transmission Operators and Balancing Authorities in a consistent manner.

B. Proposed Reliability Standards and Definitions

1. Proposed Definitions

NERC submits two revised definitions for inclusion in the NERC Glossary: (i) Real-time Assessment, and (ii) Operational Planning Analysis. The additional specificity reflected in the proposed definitions addresses concerns raised in the TOP/IRO NOPR and recommendations in the Southwest Outage Report, as discussed below. The revisions in the proposed definitions are intended to make sure that Operational Planning Analyses and Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness for next-day planning and real-time operations, respectively. The current and proposed definitions of Real-time Assessment and Operational Planning Analysis are provided below.

a) "Real-time Assessment"

The term "Real-time Assessment" is used in the following proposed Reliability Standards: TOP-001-3; TOP-003-3; IRO-002-4; IRO-008-2; IRO-010-2; and IRO-014-3. The term "Real-time Assessment" is currently defined in the NERC Glossary as "[a]n examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." The proposed definition of "Real-time Assessment" is:

> An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The proposed definition adds additional detail and clarity on the data or inputs that must be evaluated in a Real-time Assessment. The proposed definition will lead to improved assessments, and, in turn, more reliable operations. The proposed definition incorporates the defined term "Contingency" to add clarity regarding the existing and expected system conditions that are examined in a Real-time Assessment. "Contingency" is defined in the NERC Glossary as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." The proposed definition also includes additional specificity regarding the various inputs for the assessment and how that information may be provided such as through third-party services. The use of third-party services may provide smaller entities an efficient method for complying with the requirements. The additional specificity in the proposed definition ensures that assessments contain sufficient details to result in an appropriate level of situational awareness.

b) "Operational Planning Analysis"

The proposed definition of "Operational Planning Analysis" is used in the following proposed Reliability Standards: TOP-002-4; TOP-003-3; IRO-002-4; IRO-008-2; IRO-010-2; and IRO-014-3. The term "Operational Planning Analysis" is defined in the NERC Glossary as follows:

> An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

The proposed definition of Operational Planning Analysis is:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

As with the definition of "Real-time Assessment," the proposed definition for Operational Planning Analysis incorporates the defined term "Contingency" to add clarity regarding the existing and expected system conditions examined in an Operational Planning Analysis, which are undefined in the current definition. The proposed definition also includes additional specificity regarding the various inputs for the analysis and how that information may be provided such as through third-party services, which may provide smaller entities an efficient method for complying with the requirements. The proposed definition removes the language specifying that the Operational Planning Analysis may be performed "either a day ahead or as much as 12 months ahead." The standard drafting team concluded that the time-frame was unnecessary for the reliability objective, which is to obtain an evaluation of projected system conditions for next-day operations based on specified inputs.

c) *"Operating Instruction"*

The NERC Glossary term "Operating Instruction", which was submitted on May 29, 2014, is used in proposed Reliability Standards TOP-001-3 and IRO-001-4.[17] The propose definition for the term "Operating Instruction" is as follows:

> A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

As used in proposed Reliability Standard TOP-001-3, an Operating Instruction is the means by which a Transmission Operator directs entities to act to address the reliability of its Transmission Operator Area. Similarly, as used in proposed Reliability Standard, IRO-001-4, an Operating Instruction is the means by which a Reliability Coordinator directs entities to act to address the reliability of its Reliability Coordinator Area. It replaces the terms "directive" and "reliability directive" used in currently effective Reliability Standards TOP-001-1a and IRO-001-1.1.

By focusing on commands that "change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System," the definition does not attempt to differentiate between commands given in an Emergency condition or a non-Emergency condition. Further, as explained in the COM-001-2 and COM-002-4 filing, a "command," as used in the proposed definition, purposely does not specify whether the coverage is restricted to oral or written commands. Rather, the proposed Requirements in COM-002-4

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[17] The definition for "Operating Instruction" was developed and submitted to the applicable governmental authorities along with the proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocols). As noted above, on September 18, 2014, FERC issued a Notice of Proposed Rulemaking proposing to adopt the proposed Reliability Standards and new proposed definitions (including Operating Instruction), as well as the implementation plans, VRFs, and VSLs for the proposed Reliability Standards.

specify protocols using the qualifiers “oral” and “written” in the Requirements themselves. As a result, where used in the proposed TOP and IRO Reliability Standards, “Operating Instruction” carries the broader meaning, which captures both. The proposed definition also includes a clarifying note in parentheses that general discussions are not considered Operating Instructions.

2. Proposed Reliability Standards

a) Proposed Reliability Standard TOP-001-3 (Transmission Operations)

Proposed Reliability Standard TOP-001-3 (Transmission Operations) contains twenty requirements relating to transmission operations. As shown in Exhibit D, proposed Reliability Standard TOP-001-3 replaces relevant requirements from TOP-001-1a (Reliability Responsibilities and Authorities) and other currently effective TOP and IRO Reliability Standards proposed for retirement. The purpose of proposed Reliability Standard TOP-001-3 is to prevent instability, uncontrolled separation, or Cascading outages that adversely affect the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences. The proposed standard achieves this reliability goal by providing appropriate entities with the authority to take actions, or direct the actions of others, to maintain reliability during Real-time operations. It includes Real-time monitoring and Real-time assessment requirements to preserve reliability and ensure that applicable entities identify and address SOL exceedances. The proposed Reliability Standard also requires entities to communicate with each other regarding issues that could affect transmission operations. The proposed Reliability Standard applies to Balancing Authorities, Transmission Operators, Generator Operators, and Distribution Providers. The following is a description of each of the requirements in TOP-001-3.

Requirements R1 and R2 require each Transmission Operator (Requirement R1) and Balancing Authority (Requirement R2) to act to address the reliability of its area through its own actions or by issuing Operating Instructions. These requirements establishes an explicit, affirmative obligation to act. In contrast, as noted by the IERP, the obligation to act in currently effective Reliability Standard TOP-001-1a is only an implied requirement.

Requirement R3 provides that each Balancing Authority, Generator Operator, and Distribution Provider must comply with each Operating Instruction issued by its Transmission Operator(s), unless doing so would violate safety, equipment, regulatory, or statutory requirements or the action cannot be physically implemented.

Requirement R4 provides that each Balancing Authority, Generator Operator, or Distribution Provider must notify the Transmission Operator if it is unable to comply with the Transmission Operator's Operating Instruction.

Requirements R5 requires that each Transmission Operator, Generator Operator, and Distribution Provider comply with each Operating Instruction issued by its Balancing Authority, unless it cannot physically implemented the action or it would violate safety, equipment, regulatory, or statutory requirements.

Requirement R6 requires each Transmission Operator, Generator Operator, and Distribution Provider to inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.[18]

Requirement R7 provides that each Transmission Operator must assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless doing so would violate safety, equipment, regulatory, or statutory requirements or such

[18] The responsibility of Reliability Coordinators to act or direct others to act is addressed in proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities).

assistance cannot be physically implemented. The proposed requirement creates a clear obligation for a Transmission Operator to provide assistance within its capability (i.e. "if requested and able"), and maintains the implicit obligation that the requesting Transmission Operator is also taking similar action (i.e. "has implemented its comparable emergency procedures").

Requirement R8 provides that each Transmission Operator must inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of the Transmission Operator's actual or expected operations that result in, or could result in, an Emergency.

Requirements R9, R16, and R17 address outage coordination of monitoring and control equipment. Proposed Requirement R9 provides that each Balancing Authority and Transmission Operator must notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Requirement R9 includes additional terms, as described in Section IV.C below in response to the Southwest Outage Report Recommendation #15. Proposed Requirements R16 and R17 provide that each Transmission Operator (Requirement R16) and each Balancing Authority (Requirement R17) must provide its System Operators with the authority to approve planned outages and maintenance.

Requirement R10 addresses Transmission Operator monitoring obligations to help ensure that Transmission Operators have the necessary situational awareness to maintain reliable operations. The proposed requirement is derived from currently effective Reliability Standard

IRO-003-2, Requirement R1, which covers the monitoring obligations of Reliability Coordinators. Requirement R10 provides that each Transmission Operator must take certain steps for determining SOL exceedances within its Transmission Operator Area. Specifically, within its area, each Transmission Operator must monitor Facilities and the status of Special Protection Systems. Outside its area, the Transmission Operator must obtain and use status, voltages, and flow data for Facilities and the status of Special Protection Systems. Requirement R10 addresses FERC's concerns that the Pending TOP/IRO Standards did not have sufficient requirements for real-time monitoring.[19]

Requirement R11 is the equivalent of Requirement R10 for Balancing Authorities. Under Requirement R11, each Balancing Authority is required to monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Requirement R12 provides that each Transmission Operator must not operate outside of any identified IROL for a continuous duration exceeding its associated IROL T_v.

Requirement R13 provides that each Transmission Operator must ensure that a Real-time Assessment is performed at least once every 30 minutes. This proposed requirement is derived from Reliability Standard IRO-008-1, Requirement R2, which applies to Reliability Coordinators, and will significantly improve situational awareness.[20]

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19 TOP/IRO NOPR at P 60.

20 As described below, proposed Reliability Standard TOP-002-4, Requirement R2 requires Transmission Operators to have an Operating Plan for next-day operations. It is appropriate for an Operating Plan to contain guidance for performing Real-time Assessments with detailed instructions and timing requirements to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Requirement R14 provides that each Transmission Operator must initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.[21] As discussed below, proposed Reliability Standard TOP-002-4, Requirement R3 requires Transmission Operators to have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances.

Requirement R15 provides that each Transmission Operator must inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded.

Requirement R18 provides that each Transmission Operator must operate to the most limiting parameter in instances where there is a difference in SOLs. As shown in Exhibit D, this Requirement is from currently effective IRO-005-3.1a, Requirement R10. The phrase "derived limits" in IRO-005-3.1a R10 is replaced with "SOLs" for clarity and consistency.

Requirements R19 and R20 provide that each Transmission Operator (Requirement R19) and Balancing Authority (Requirement R20) must have data exchange capabilities with the entities from which it needs data in order to maintain reliability in its area. Proposed Requirements R19 and R20 are consistent with proposed Reliability Standard IRO-002-4, Requirement R1, which provides that each Reliability Coordinator must have data exchange capabilities with its Balancing Authorities, Transmission Operators, and other entities it deems necessary. These data exchange capabilities are required to support the data specifications required in proposed Reliability Standard TOP-003-3, as discussed below.

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21 An "Operating Plan" is defined in the NERC Glossary as:

> A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

b) Proposed Reliability Standard TOP-002-4 (Operations Planning)

Proposed Reliability Standard TOP-002-4 (Operations Planning) contains seven requirements relating to operations planning for Transmission Operators and Balancing Authorities, replacing relevant requirements from Reliability Standard TOP-002-1b (Normal Operations Planning) and other TOP and IRO Reliability Standards proposed for retirement, as shown in Exhibit D hereto. The purpose of proposed Reliability Standard TOP-002-4 is to ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits. Specifically, the proposed standard addresses next-day planning and operations and provide for the necessary notifications and coordination between various functional entities. The revised definition of Operational Planning Analysis is an integral component of proposed TOP-002-4 and specifies the scope and inputs required for next-day analyses. The proposed standard also improves coordination of next-day operations by requiring Transmission Operators and Balancing Authorities to provide Operating Plans to their Reliability Coordinators. Proposed Requirements R1 through R3 and R6 apply to Transmission Operators, and proposed Requirements R4, R5, and R7 apply to Balancing Authorities. The following is a description of each of the requirements in TOP-002-4.

Requirement R1 requires each Transmission Operator to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs.

Requirement R2 requires each Transmission Operator to have an Operating Plan (or Plans) for next-day operations to address potential SOL exceedances identified in the Operational Planning Analysis performed pursuant to Requirement R1.

Requirement R4 requires each Balancing Authority to have an Operating Plan (or Plans) for the next day that address four items: (i) expected generation resource commitment and dispatch; (ii) interchange scheduling; (iii) demand patterns; and (iv) capacity and energy reserve requirements, including deliverability capability.

Requirements R3 and R5 require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R5) to notify the entities identified in their Operating Plan as to their roles in that plan.

Requirements R6 and R7 require each Transmission Operator (Requirement R6) and Balancing Authority (Requirement R7) to provide its plan to its Reliability Coordinator.

c) Proposed Reliability Standard TOP-003-3 (Operational Reliability Data)

Proposed Reliability Standard TOP-003-3 (Operational Reliability Data) establishes requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations, replacing relevant requirements from Reliability Standard TOP-003-1, as shown in Exhibit D. The purpose of proposed Reliability Standard TOP-003-3 is to ensure that Transmission Operators and Balancing Authorities have the data needed to fulfill their operational and planning responsibilities. Proposed TOP-003-3 is derived from the approach for Reliability Coordinators in Reliability Standard IRO-010-1a to improve the flow of operational reliability data needed by Transmission Operators and Balancing Authorities.[22]

The proposed Reliability Standard consists of five Requirements, including requirements for Balancing Authorities and Transmission Operators to maintain and distribute to relevant

[22] Proposed Reliability Standard IRO-010-2 replaces Reliability Standard IRO-010-1a and contains the data specification requirements for Reliability Coordinators.

entities data specifications needed to perform various analyses and assessments. The proposed Reliability Standard also requires entities receiving data specifications to respond according to mutually agreed upon parameters. The following is a description of each of the Requirements in TOP-003-3.

Requirement R1 requires each Transmission Operator to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include, but is not limited to:

- a list of data and information needed to support these analyses, monitoring, and assessments;
- provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirement R2 requires each Balancing Authority to maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification must include:

- a list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring;
- provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirements R3 and R4 require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R4) to distribute its data specification to the entities that have the necessary data.

Requirement R5 requires each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification using: (i) a mutually agreeable format; (ii) a mutually agreeable process for resolving data conflicts; and (iii) a mutually agreeable security protocol.

Data specification and collection for Reliability Coordinators is addressed in proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection), discussed below.

d) Proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities)

Proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities) contains requirements relating to the Reliability Coordinator's overall responsibility for reliable operation within the Reliability Coordinator Area. The purpose of the proposed Reliability Standard is to establish the responsibility of Reliability Coordinators to act or direct others to act to address the reliability of the Reliability Coordinator Area. The proposed Reliability Standard is applicable to Reliability Coordinators, Transmission Operators, Balancing Authorities, Generator Operators, and Distribution Providers, which is consistent with the entities that are listed as receiving instructions from the Reliability Coordinator in the NERC functional model. The Transmission Service Provider is not an applicable entity as it does not perform an operating reliability function under the direction of the Reliability Coordinator, as described in the NERC Functional Model.

The proposed Reliability Standard contains the following three requirements:

- *Requirement R1* provides that each Reliability Coordinator must act to address the reliability of its Reliability Coordinator Area through direct actions or by issuing Operating Instructions.

- *Requirement R2* provides that each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider must comply with its Reliability Coordinator's Operating Instructions unless compliance cannot be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements.

- *Requirement R3* provides that a Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider informs the Reliability Coordinator that it is unable to perform an Operating Instruction issued by its Reliability Coordinator.

e) Proposed Reliability Standard IRO-002-4 (Reliability Coordination – Monitoring and Analysis)

Proposed Reliability Standard IRO-002-4 (Reliability Coordination – Monitoring and Analysis) contains requirements relating to capabilities for monitoring and analysis of Real-time operating data. The purpose of the proposed Reliability Standard is to provide System Operators with the capabilities necessary to monitor and analyze data needed to perform reliability functions.

The proposed Reliability Standard consists of the following four requirements:

- *Requirement R1* requires each Reliability Coordinator to have data exchange capabilities with its Balancing Authorities, Transmission Operators, and other entities as it deems necessary, for it to perform the Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

- *Requirement R2* provides that each Reliability Coordinator must provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring, and analysis capabilities.

- *Requirement R3* provides that each Reliability Coordinator must monitor Facilities, the status of Special Protection Systems, and non-Bulk Electric System facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to identify any SOL or IROL exceedances within its Reliability Coordinator Area.

- *Requirement R4* provides that each Reliability Coordinator must have monitoring systems that provide information used by the Reliability Coordinator's operating personnel, with particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

f) Proposed Reliability Standard IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments)

Proposed Reliability Standard IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments) contains requirements for Reliability Coordinators to conduct next-day analyses and assessments of operating conditions in Real-time to help prevent instability, uncontrolled separation, or Cascading. The proposed definitions of Operational Planning Analysis and Real-time Assessment are integral components of proposed IRO-008-2 as they specify the scope and inputs for next-day analysis and real-time assessments of operating conditions in Real-time. Furthermore, proposed IRO-008-2 enhances next-day operations planning by specifying requirements for coordination of the Reliability Coordinator's Operating Plan to address potential SOL and IROL exceedances.

The proposed Reliability Standard consists of the following six requirements, designed to ensure that Reliability Coordinators perform analyses to identify potential or actual SOL or IROL exceedances and that such exceedances are addressed in a coordinated fashion:

- *Requirement R1* provides that each Reliability Coordinator must perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed SOLs and IROLs within its Wide Area.

- *Requirement R2* provides that each Reliability Coordinator must have a coordinated Operating Plan for next-day operations to address potential SOL and IROLs exceedances identified as a result of its Operating Planning Analysis performed pursuant to Requirement R1. The coordinated Operating Plan must consider the Operating Plans provided by its Transmission Operators and Balancing Authorities pursuant to Requirements R6 and R7 of proposed Reliability Standard TOP-002-4.

- *Requirement R3* provides that each Reliability Coordinator must notify impacted entities identified in its Requirement R2 Operating Plan as to their role in the plan.

- *Requirement R4* provides that each Reliability Coordinator must ensure that a Real-time Assessment is performed at least once every 30 minutes.

- *Requirement R5* provides that each Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

- *Requirement R6* provides that each Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated.

g) *Proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection)*

Proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection) provides a mechanism for the Reliability Coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or Cascading outages. Proposed Reliability Standard IRO-010-2 reflects recommendations from Southwest Outage Report, including more clearly identifying necessary data and information to be included in the Reliability Coordinator's data specification.

The proposed Reliability Standard consists of the following three requirements:

- *Requirement R1* provides that the Reliability Coordinator must maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include:
    - a list of data and information necessary to support Reliability Coordinator Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, including non-Bulk Electric System data and external network data, as deemed necessary by the Reliability Coordinator;
    - provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
    - a periodicity for providing data; and
    - the deadline by which the respondent is to provide the indicated data.

- *Requirement R2* provides that the Reliability Coordinator must distribute its data specification to entities that have the required data.

- *Requirement R3* provides that each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification must satisfy the obligations of the documented specifications using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

h) Proposed Reliability Standard IRO-014-3 (Coordination Among Reliability Coordinators)

Proposed Reliability Standard IRO-014-3 (Coordination Among Reliability Coordinators) contains requirements for coordination for interconnected operations at the Reliability Coordinator level. The purpose of the proposed Reliability Standard is to ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely affect other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

The proposed Reliability Standard consists of the following seven requirements:

- *Requirement R1* requires each Reliability Coordinator to have and implement Operating Procedures, Processes, or Plans for activities that require notification or coordination of actions that may affect adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Processes, or Plans must include, at a minimum: (i) criteria and processes for notifications; (ii) energy and capacity shortages; (iii) control of voltage, including the coordination of reactive resources; (iv) exchange of information, including planned and unplanned outage information to support Operational Planning Analyses and Real-time Assessments; and (v) provisions for periodic communications to support reliable operations.

- *Requirement R2* requires each Reliability Coordinator to maintain its Operating Procedures, Processes, or Plans through annual reviews and updates, with no more than 15 months passing between reviews. For each update, the Reliability Coordinator is required to obtain written agreement from the other Reliability Coordinators required to take the indicated action and distribute the Operating Procedures, Process, or Plans within 30 days of an update.

- *Requirement R3* requires each Reliability Coordinator to notify other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

- *Requirement R4* specifies that, in the event Reliability Coordinators disagree on the existence of an Emergency, each impacted Reliability Coordinator must operate as though an Emergency exists.

- *Requirement R5* provides that each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area must develop an action plan to resolve the Emergency.

- *Requirement R6* provides that each impacted Reliability Coordinator must implement the action plan developed by the Reliability Coordinator that identifies the Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

- Requirement R7 requires each Reliability Coordinator to assist other Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its Emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. The proposed requirement creates an affirmative obligation for the Reliability Coordinator to provide assistance within its capability (i.e. "if requested and able"), and maintains the implicit obligation that the requesting Reliability Coordinator is also taking similar action (i.e. 'has implemented its emergency procedures").

i) Proposed Reliability Standard IRO-017-1 (Outage Coordination)

Proposed Reliability Standard IRO-017-1 (Outage Coordination) is a new Reliability Standard designed to ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.[23] Transmission Planning and Operations Planning involve different functional entities per the NERC Functional Model. Furthermore, these two types of planning involve different objectives, information, timeframes, and processes. The requirements in the proposed Reliability Standard, which span both time horizons, provide the necessary requirements for effective coordination of planned outages to support reliable operations.

Proposed Reliability Standard IRO-017-1 consists of the following four requirements to address planned outage coordination concerns.

[23] The Operations Planning time horizon refers to "operating and resource plans from day-ahead up to and including seasonal." *See* Time Horizons, *available at* http://www.nerc.com/files/Time_Horizons.pdf. The term Near-Term Transmission Planning Horizon is defined in the NERC Glossary as "[t]he transmission planning period that covers Year One through five."

- *Requirement R1* provides that each Reliability Coordinator must develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. This process must:
    - identify applicable roles and reporting responsibilities, including development and communication of outage schedules and assignment of coordination responsibilities for outage schedules between Transmission Operators and Balancing Authorities;
    - specify outage submission timing requirements;
    - define the process to evaluate the impact of Transmission and generation outages with the Reliability Coordinator's Wide Area; and
    - define the process to coordinate the resolution of identified outage conflicts with Transmission Operators and Balancing Authorities, as well as other Reliability Coordinators.
- *Requirement R2* provides that each Transmission Operator and Balancing Authority must perform the functions specified in its Reliability Coordinator's outage coordination process.
- Requirement R3 provides that each Planning Coordinator and Transmission Planner must provide its Planning Assessment to impacted Reliability Coordinators.[24] Planning Coordinators and Transmission Planners are required to develop Planning Assessments under the currently effective Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).
- Requirement R4 requires each Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

C. Consideration of the Southwest Outage Report Recommendations

The following section discusses the manner in which the proposed Reliability Standards address the recommendations of the Southwest Outage Report. On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power ("2011

[24] Planning Assessment is defined in the NERC Glossary as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Southwest Outage"). The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers in the region losing power, some for up to 12 hours.[25]

Following the 2011 Southwest Outage, NERC and FERC conducted a joint investigation. The investigation concluded that the cause of the disturbance stemmed primarily from weaknesses in operations planning and real-time situational awareness, which, if conducted properly, would have allowed system operators to proactively operate the system in a secure state during normal system conditions and to restore the system to a secure state as soon as possible.[26]

On April 27, 2012, FERC and NERC issued the Southwest Outage Report, outlining the investigators' findings and making recommendations for reliability improvements. The Southwest Outage Report made twenty-seven (27) findings and associated recommendations applicable mostly to Transmission Operators, Balancing Authorities, and Reliability Coordinators. These findings and recommendations addressed the lack of adequate operations planning and real-time situational awareness of contingency conditions, as well as other factors that contributed to the 2011 Southwest Outage.[27] The Southwest Outage Report findings are

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[25] Southwest Outage Report at 1.

[26] *Id*. at 5.

[27] The Southwest Outage Report concluded that several other factors contributed to the 2011 Southwest Outage. For example, the Reliability Coordinator and the affected entities did not consistently recognize the adverse impact that sub-100 kV facilities can have on the Bulk-Power System reliability. Furthermore, there were significant issues with Protection System settings. *See* Southwest Outage Report pp. 63-110 and Appendix B: Table of Findings and Recommendations.

divided into eight categories,[28] and each category lists specific reliability issues identified during the joint investigation.

As part of Project 2014-03, the standard drafting team considered the Southwest Outage Report findings and recommendations applicable to Transmission Operators, Balancing Authorities and Reliability Coordinators, and addressed these recommendations in the language of the proposed Reliability Standards.[29] Several of the findings and recommendations were outside the scope of Project 2014-03 either fully, or partially, as discussed in this section of the filing.[30] Below is a short description of each applicable finding and recommendation identified in the Southwest Outage Report,[31] and an explanation of how the proposed Reliability Standards address the reliability issues identified following the 2011 Southwest Outage. The full listing of the recommendations and mapping to the proposed TOP and IRO Reliability Standards is provided in Exhibit F. A summary of the findings and recommendations is available in Appendix B of the Southwest Outage Report.

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28 The eight categories of findings are: next-day planning, seasonal planning, near-and long-term planning, situational awareness, consideration of Bulk Electric System equipment, Interchange System Operating Limits (IROLs) derivations, Protection Systems, and angular separation. *See* Southwest Outage Report, Appendix B.

29 *See* Exhibit F Mapping of Revised TOP and IRO Reliability Standards to Address 2012 Southwest Outage Report Recommendations ("Southwest Outage Recommendation Mapping Document"). Several of the Southwest Outage Report recommendations were specific to the particular facts and circumstances of the 2011 Southwest Outage, and were not addressed in the Southwest Outage Recommendation Mapping Document. The Southwest Outage Report identified weaknesses in WECC seasonal planning, but the standard drafting team determined that these weaknesses should not become prescriptive requirements for all Reliability Coordinator areas.

30 *Id.*

31 *See* Southwest Outage Report, Appendix B for a list of all findings and recommendations included in the Southwest Outage Recommendation Mapping Document and this filing.

1. Operations Planning

Eight findings in the Southwest Outage Report relate to operations planning.[32] The Southwest Outage Report's next-day and seasonal planning recommendations fall within this category and were considered together by the standard drafting team.

As described more fully below, the Southwest Outage Report recommendations related to operations planning are addressed generally by proposed Reliability Standards IRO-017-1, TOP-002-4 and IRO-008-2. Proposed Reliability Standard IRO-017-1 addresses the outage coordination concerns identified in the Southwest Outage Report, as its purpose is to ensure that outages are properly coordinated in the Operations Planning Time Horizon and Near-Term Transmission Planning Horizon. Outage coordination in the Operations Planning Time Horizon supports the needs of the Transmission Operators and the Reliability Coordinators to plan for reliable next-day operations, as required by the proposed TOP-002-4 and IRO-008-2. Specific considerations related to each finding are included below.

Finding #1: Failure to Conduct and Share Next-Day Studies

The Southwest Outage Report concluded that not all of the affected Transmission Operators conduct next-day studies or share their studies with the neighboring Transmission Operator and the Reliability Coordinator. Accordingly, recommendation #1 suggested that all Transmission Operators should conduct next-day studies and share the results with neighboring Transmission Operators and the Reliability Coordinator (before the next day). This measure was proposed to ensure that all contingencies that could affect the Bulk-Power System are studied.

[32] The standard drafting team referenced the definition of "Operations Planning Time Horizon" to group items. This definition includes "operating and resource plans from day-ahead up to and including seasonal."

The proposed language of TOP-002-4, Requirements R1, R3, and R6 directly addresses this recommendation by requiring Transmission Operators to conduct next-day studies (Requirement R1), share the results of the studies with the registered entities identified in the Operating Plan(s) (Requirement R3), and provide the results to the Reliability Coordinator (Requirement R6).

Finding #2: Lack of Updated External Networks in Next-Day Study Models

The Southwest Outage Report determined that when conducting next-day studies, some affected Transmission Operators used models that do not reflect next-day operating conditions external to their systems. Recommendation #2 stated that Transmission Operators and Balancing Authorities update their studies to reflect these conditions. Such external operating conditions include generation and transmission outages and scheduled Interchanges.

Proposed Reliability Standards TOP-002-4, Requirement R1 and TOP-003-3 Requirement R1, Part 1.1, and the proposed definition of Operational Planning Analysis address this particular reliability concern. Specifically, TOP-002-4 Requirement R1 requires the Transmission Operators to have Operational Planning Analysis for the next day, which under the proposed definition includes external operating conditions like Interchange data, transmission and generator outages, and identified equipment limitations. In addition, proposed Reliability Standard TOP-003-3 Requirement R1, Part 1.1 requires Transmission Operators to maintain a documented specification for the data they need to support Operational Planning Analyses, including external network data. Furthermore, recommendation #2 suggested that Transmission Operators and Balancing Authorities should take the necessary steps to allow free exchange of next-day operational data between operating entities. TOP-003-3 Requirements R1, R2 and R5 address this reliability issue. Requirement R1 directs Transmission Operators to maintain data specification for the data necessary to perform Operational Planning Analysis, and Requirement R2 establishes a similar obligation for Balancing Authorities. Requirement R5 requires Transmission Operators, Balancing Authorities, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Owners, and Distribution Providers to satisfy any requests for information included in the proposed Reliability Standard that are necessary for completion of the required Operational Planning Analysis.

The same recommendation also concluded that the Reliability Coordinators should review the procedures for coordinating next-day studies within their region, ensure adequate data exchange among Balancing Authorities and Transmission Operators, and facilitate the next-day studies conducted by Balancing Authorities and Transmission Operators. This issue is addressed in proposed IRO-008-2 R2, which directs Reliability Coordinators to have coordinated Operating Plans(s) for next-day operations. These coordinated Operating Plans aim to timely and adequately address reliability issues identified in the next-day Operational Planning Analysis.

Finding #3: Sub-100 kV Facilities not Adequately Considered in Next-Day Studies

In the Southwest Outage Report, NERC and FERC staff determined that in conducting next-day studies, some Transmission Operators do not adequately consider lower-voltage facilities below 100 kV. Recommendation #3 stated that Transmission Operators and Reliability Coordinators should ensure their next-day studies include all internal and external facilities (including those below 100 kV) that can affect Bulk-Power System reliability. Proposed TOP-003-3 R1.1 and IRO-010-2 R1.1 address this by specifically requiring Transmission Operators and Reliability Coordinators to incorporate any non-Bulk Electric System data deemed necessary into their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Finding #4: Flawed Process for Estimating Scheduled Interchanges

During the 2011 Southwest Outage investigation, NERC and FERC staff determined that the Reliability Coordinator process for estimating scheduled Interchanges was not adequate to ensure that such values were accurately reflected in the Reliability Coordinator's next-day studies. Recommendation #4 suggested that the Reliability Coordinator involved in the event should improve its process for predicting Interchanges in the day-ahead timeframe. In the proposed definition of Operational Planning Analysis, Interchange data is an included input of next-day studies, which addresses this recommendation.

Finding #5: Lack of Coordination in Seasonal Planning Process

The Southwest Outage Report concluded that due to a lack of coordination in the seasonal planning process in the Western Electricity Coordinating Council ("WECC") region, Transmission Operators may fail to identify contingencies in one subregion that could affect other Transmission Operators in the same or another subregion. Recommendation #5 addresses this issue by recommending that the individual Transmission Operators should conduct a full contingency seasonal analysis to identify contingencies outside their own systems and share the analysis with the other affected Transmission Operators.[33]

Proposed Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3 address coordination of operational planning among Transmission Operators by requiring Transmission Operators to gather external data deemed necessary to perform analysis and share the results of the studies with the affected entities. Furthermore, proposed Reliability Standard IRO-017-1 requires Reliability Coordinators to establish an outage coordination

[33] This recommendation also included language related to actions of the WECC Regional Entity. This section of the recommendation was not considered by the standard drafting because it is not applicable to Reliability Coordinators, Transmission Operators and Balancing Authorities and falls outside the scope of Project 2014-03.

process that will identify and resolve transmission and generation planned outage issues in the Operations Planning Time Horizon, which includes next-day and seasonal planning periods that have the potential to impact the Reliability Coordinator's wide-area.

Finding #6: External and Lower-Voltage Facilities not Adequately Considered in Seasonal Planning Process

The Southwest Outage Report concluded in recommendation #6 that the focus of Transmission Operator seasonal planning should be expanded to include external facilities and internal and external sub-100 kV facilities that affect Bulk-Power System reliability. This reliability concern is addressed in TOP-003-3, Requirement R1, which requires Transmission Operators to obtain external network and sub-100 kV data deemed necessary for use in Operational Planning Analyses. Additionally, the outage coordination process established by Reliability Coordinators, as required by proposed IRO-017-1, must specifically address wide-area issues. In this manner, the proposed Reliability Standards collectively ensure that the scope of operations planning from day-ahead up to and including seasonal planning extends beyond the individual Transmission Operator Area and is coordinated across the Reliability Coordinator Area. Furthermore, proposed Reliability Standard IRO-017-1, Requirement R1 specifies that the Reliability Coordinator's outage coordination process must include a process for resolving planned outage conflicts with other Reliability Coordinators.

Finding #7: Failure to Study Multiple Load Levels

The Southwest Outage Report determined that Transmission Operators in WECC do not always conduct their individual planning studies based on multiple base cases, and as a result, some contingencies could be missed and excluded from the studies. FERC and NERC staff suggested in recommendation #7 that Transmission Operators include in their seasonal studies multiple base cases and generation maintenance outages, as well as dispatch scenarios during high-load shoulder periods. The standard drafting team addressed this issue by including a broader definition of Operational Planning Analysis, under which projected system conditions such as load forecasts and generation output levels must be considered by Transmission Operators and Reliability Coordinators. Such projected system conditions would include generator outages and high-load periods. Additionally, the outage coordination process established by Reliability Coordinators as required by proposed IRO-017-1 must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area. The Reliability Coordinator's outage coordination process covers the Operations Planning Time Horizon, which spans from day-ahead up to and including seasonal planning.

Finding #8: Not Sharing Overload Relay Trip Setting

Recommendation #8 of the Southwest Outage Report recommended that Transmission Operators include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that affect the Bulk-Power System. This reliability concern is addressed in proposed Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3, and in the associated definition of Operational Planning Analysis. TOP-003-3, Requirement R1 requires Transmission Operators to maintain provisions for notification of current Protection System and Special Protection System status or degradation that affects system reliability. The proposed Reliability Standard TOP-002-4, Requirement R3 requires sharing of the study results among the Transmission Operators. Furthermore, the definition of Operational Planning Analysis explicitly requires that Protection Systems be included in the pre-and-post contingency studies.

Additionally, the Reliability Coordinators must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area as required by proposed IRO-017-1. This process would include relevant system inputs necessary to evaluate the impact of transmission and generation planned outages on the reliable operation of the Bulk Power System. The Reliability Coordinator's outage coordination process covers the Operations Planning Time Horizon, which spans from day-ahead up to and including seasonal planning.

2. Near-and-long term planning

Finding #9: Gaps in Planning Process

Recommendation #9 of the Southwest Outage Report recommended that Transmission Operators[34] develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all Protection Systems, including remedial action schemes (RASs), Safety Nets (such as the San Onofre Nuclear Generating Station (SONGS) separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on Bulk-Power System reliability. This reliability concern is addressed in proposed Reliability Standard TOP-003-3, Requirement R1, Part 1.1 and 1.2 and the proposed definition of Operational Planning Analysis, as discussed above.

3. Situational Awareness

Finding #11: Lack of Real-Time External Visibility

NERC and FERC staff concluded in the Southwest Outage Report that Transmission Operators have limited real-time visibility outside their systems and lack adequate situational awareness of external contingencies. Accordingly, recommendation #11 proposed that Transmission Operators engage in more real-time data sharing and obtain sufficient data to monitor significant external facilities in real-time. Proposed Reliability Standard TOP-003-3

[34] This recommendation is also applicable to Planning Coordinators and Transmission Planners, which fall outside the scope of Project 2014-03. Recommendation #9 includes language applicable specifically to WECC Regional Entity, which is also outside the scope of the proposed Reliability Standards. Recommendation #10 is not applicable and was not considered by the standard drafting team.

addresses this issue by requiring Transmission Operators to include external network data in their data specifications for Operational Planning Analyses.

In addition, recommendation #11 advised that Transmission Operators review their real-time monitoring tools, such as state estimator and real-time contingency analysis ("RTCA"), to ensure that such tools reflect the critical facilities needed for the reliable operation of the Bulk Power System. The language in proposed Reliability Standard TOP-001-3, Requirement R13 addresses this reliability concern by requiring Transmission Operators to perform a Real-time Assessment at least once every 30 minutes. Furthermore, the proposed definition of Real-time Assessment includes an assessment of potential post-contingency operating conditions.

Finding #12: Inadequate Real-Time Tools

In recommendation #12, FERC and NERC staff advised that Transmission Operators should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems. Proposed Reliability Standard TOP-001-3, Requirement R13, as described in detail above, is designed to resolve this specific issue by requiring Transmission Operators to ensure a Real-time Assessment is performed at least once every 30 minutes.

Finding #13: Reliance on Post-Contingency Mitigation Plans

The Southwest Outage Report determined that post-contingency mitigation plans are not viable under all circumstances and suggested in recommendation #13 that Transmission Operators review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions to return the system to a secure state. Proposed Reliability Standards TOP-002-4, Requirement R2 and TOP-001-3, Requirement R14 resolve this issue by requiring Transmission Operators to have an Operating

Plan to address SOL exceedances, and initiate the Operating Plan to mitigate an exceedance as part of its real-time monitoring or assessment.

In addition, the standard drafting team has developed a white paper on SOL definition and exceedance criteria (the "SOL White Paper"), which clarified the standard drafting team's position on establishing and exceeding SOLs, and on implementing Operating Plans to mitigate exceedances.[35] The SOL White Paper provides important linkages between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective Operating Plans to mitigate SOL exceedances.

Finally, recommendation #13 advised that as part of the review of existing operating processes and procedures, Transmission Operators should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures. This reliability concern is addressed in proposed Reliability Standard TOP-003-3, Requirement R1, and the proposed definitions of Operational Planning Analysis and Real-time Assessment, which collectively require the acquisition of Protection System data, such as relays that automatically isolate facilities, as an item to be included in the TOP studies.

Finding #15: Failure to Notify WECC Reliability Coordinator and the Neighboring Transmission Operators Upon Losing Real Time Contingency Analysis (RTCA) Capability

During the 2011 Southwest Outage, at least one affected Transmission Operator lost the ability to conduct RTCA more than 30 minutes prior to, and throughout the course of the event. As a result, recommendation #15 suggested that Transmission Operators should ensure

[35] *System Operating Limit Definition and Exceedance Clarification*, White Paper (May 2014). Available at: http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_first_posting_white_paper_sol_exceedance_20140509.pdf

procedures and training[36] are in place to notify WECC Reliability Coordinator and neighboring Transmission Operators and Balancing Authorities promptly after losing RTCA capabilities. Proposed TOP-001-3, Requirement R9, which requires Transmission Operators to notify affected registered entities of outages to monitoring and assessment capabilities, addresses this recommendation.

4. Consideration of Bulk Electric System Equipment

Designation of Bulk Electric System facilities is outside the scope of Project 2014-03. The proposed Reliability Standards incorporated non-Bulk Electric System data and facilities monitoring where necessary for the reliable operation of the Bulk Electric System, as shown below.

Finding #17: Impact of Sub-100 kV Facilities on Bulk Power System Reliability

The Southwest Outage Report determined that WECC Reliability Coordinator and affected Transmission Operators and Balancing Authorities did not consistently recognize the adverse impact sub-100 kV facilities could have on Bulk-Power System reliability. Recommendation #17 concluded that WECC, as the Reliability Coordinator, should lead other entities, including Transmission Operators and Balancing Authorities, to ensure that all facilities that can adversely impact Bulk-Power System reliability are either designated as part of the Bulk Electric System or otherwise incorporated into planning and operations studies, and actively monitored and alarmed in RTCA systems.

With respect to sub-100 kV facilities, the standard drafting team determined that any sub-100 kV elements that is necessary for reliable operation of the Bulk Electric System would be included as Bulk Electric System facilities through the exception process provided in Appendix

36 The training issue falls outside of the scope of Project 2014-03.

5C to the NERC Rules of Procedure.[37] The exception process provides the means for Transmission Operators and Reliability Coordinators to include Elements in the Bulk Electric System that are necessary for the reliable operation of the interconnected transmission system but were not identified in the Bulk Electric System definition.[38] Accordingly, the standard drafting team concluded it is unnecessary to include non-Bulk Electric System monitoring. In addition, proposed Reliability Standard TOP-001-3, Requirement R10 requires Transmission Operators to monitor Facilities within their Transmission Operator Area, and to obtain information deemed necessary by the Transmission Operator about such Facilities located outside of the Transmission Operator Area when determining SOL exceedances.

When non-Bulk Electric Facilities have no impact on the Bulk Electric System, but are needed for completing system models, then the FAC-001-2, Requirement R3 addresses the issue. This Reliability Standard requires the Reliability Coordinator to include in its methodology its entire Reliability Coordinator Area and critical modeling details from other Reliability Coordinator Areas that would affect the Facility under study. In addition, the Reliability Coordinator must include details of system models used to determine SOLs.

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[37] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012), *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013); *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 143 FERC ¶ 61,231, at P 13 (2013).

[38] In approving the exception process, FERC stated:

> We believe that entities, having knowledge of their systems and the concomitant planning assessments and system impact studies, will identify an element that is necessary for reliable operation of the integrated transmission network while conducting their day-to-day operations and planning and performing studies. If the element does not fall within the definition, we expect that the entity will submit the element for inclusion through the exception process. Use of this process should ensure that the all sub-100 kV elements, as well as other facilities, necessary for the operation of the interconnected transmission network are included in an 'appropriate and consistent' manner.

Order No. 773 at P 269.

Similarly, proposed Reliability Standard IRO-002-4, Requirement R4 requires each Reliability Coordinator to monitor facilities identified as necessary within its Reliability Coordinator Area and within neighboring Reliability Coordinator Areas, and to identify any SOL exceedances and to determine any IROL exceedances.

Finally, as noted above, the proposed Reliability Standards TOP-003-3, Requirement R1 and IRO-010-2, Requirement R1 incorporate non-Bulk Electric System facilities into the data used by Transmission Operators and Reliability Coordinators to support their analysis.

5. Interconnection Reliability Operating Limit Derivations

Finding #18: Failure to Establish Valid SOLs and Identify IROLs

Recommendation #18.1 of the Southwest Outage Report advised that Reliability Coordinators study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time. Reliability Standard FAC-014-2, Requirement R1 directs the Reliability Coordinator to establish SOLs and IROLs. To address the recommendation, proposed Reliability Standard IRO-008-2, Requirement R1 further specifies that each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its wide-area. In addition, IRO-008-2, Requirement R4 requires the Reliability Coordinator to perform a Real-time Assessment of system conditions at least once every 30 minutes.

6. Protection Systems

Findings #19-#26: Related to Coordination of Special Protection Systems and Remedial Action Schemes at the Reliability Coordinator and TOP level

The standard drafting team determined that currently effective Reliability Standard PRC-001 already addresses coordination of Special Protection Systems and Remedial Action Schemes. Thus, any changes to Protection System coordination falls outside the scope of Project

2014-3. Nevertheless, proposed Reliability Standards TOP-001-3, Requirement R10 and IRO-002-4, Requirement R4 address monitoring of Special Protection Systems and Remedial Action Schemes.[39] TOP-001-3, Requirement R10 Part 10.1 mandates Transmission Operators to monitor Facilities and the status of Special Protection Systems within their Transmission Operator areas, while Part 10.2 mandates the same actions for Facilities outside of a Transmission Operator's area.

7. Angular Separation

Findings #27: Phase Angle Difference Following Loss of Transmission Line

The Southwest Outage Report concluded that one of the Transmission Operators involved in the 2011 Southwest Outage did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Recommendation #27 included several possible actions to address this failure, including a suggestion that the Transmission Operators should have the tools necessary to evaluate phase angle differences following the loss of lines. Although the recommended changes related to phase angle calculation tools fall outside the scope of Project 2014-3 as it is being addressed in Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities, the proposed definition of Operational Planning Analysis and Real-time Assessment include consideration of phase angle and equipment limitations.

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[39] During the development of the proposed TOP/IRO standards, the terms Remedial Action Scheme and Special Protection System were interchangeable as defined in the NERC Glossary of Terms. On February 25, 2015 NERC submitted revisions to the definition of "*Remedial Action Scheme*" ("RAS"), which proposes to eliminate the defined term Special Protection System. Proposed TOP/IRO standards will be modified as necessary based on applicable governmental authority actions in response to this filing.

D. Consideration of TOP/IRO NOPR Concerns

In its TOP/IRO NOPR, FERC expressed certain concerns regarding the Pending TOP/IRO Standards and proposed to remand those standards for further consideration in NERC's standards development process.[40] FERC identified "Issues to be addressed" and "Issues Requiring Clarifications." As part of Project 2014-03, the standard drafting team considered the issues raised in the TOP/IRO NOPR and designed the proposed Reliability Standards to address FERC's concerns. This section discusses the manner in which the proposed Reliability Standards address each of the issues raised in the TOP/IRO NOPR. Additional information is provided in Exhibit G hereto.

1. <u>TOP Reliability Standards – Issues to be Addressed</u>

a. Plan and Operate Within All SOLs

FERC expressed concern that the Pending TOP/IRO Standards lacked a requirement for Transmission Operators to analyze and operate within all SOLs.[41] Specifically, FERC stated that while the Pending TOP/IRO Standards require Transmission Operators to plan to operate within all IROLs, they only require Transmission Operators to plan to operate within a limited subset of SOLs identified by the Transmission Operator as necessary to support reliability internal to its area.[42] FERC maintained that this limitation would reduce system reliability and cause negative consequences external to the Transmission Operator's area.[43] FERC also expressed the concern that deteriorating system conditions may result in an SOL rapidly degrading into an IROL. FERC noted further that limiting the analysis to non-IROL SOLs identified internally by the

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[40] TOP/IRO NOPR at PP 42-99.

[41] *Id*. at P 42.

[42] *Id*.

[43] *Id*. at PP 42, 51.

Transmission Operator may "reduce system reliability because operators have less situational awareness of the system and conditions."[44]

The proposed Reliability Standards address FERC's concerns by requiring Transmission Operators to plan to operate within all SOLs. Proposed Reliability TOP-001-3, Requirement R14 requires "each Transmission Operator to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." Further, proposed TOP-001-3, Requirement R15 requires that each Transmission Operator inform its Reliability Coordinator of actions taken to resolve the SOL exceedance. Proposed IRO-008-2, Requirements R1, R2, R5, and R6 now include coverage of SOLs, which resolves FERC's concern that the previously-proposed Reliability Standards limited "non-IROL SOLs" to only those internally identified by the Transmission Operator.

FERC also proposed that the Transmission Operator should be required "to have an operational plan to operate within all Bulk-Power System IROLs and SOLs for all cases when facility ratings or stability limits are exceeded during anticipated normal and contingency event conditions."[45] FERC noted that this operational plan "is needed to ensure that a Transmission Operator operates in, or can return its system to, a reliable operating state" and that a Transmission Operator should have plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.[46]

To address FERC's concerns,[47] proposed Reliability Standard TOP-002-4 requires, among other things, that Transmission Operators have: (1) an Operational Planning Analysis that

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44 *Id*. at P 52.

45 TOP/IRO NOPR at P 54.

46 *Id*. at P 54.

47 *Id*.

will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs; and (2) an Operating Plans for next-day operations to address potential SOL exceedances identified as a result of its Operational Planning Analysis. Further, as noted above, proposed Reliability TOP-001-3, Requirement R14 requires Transmission Operators to initiate their Operating Plans to mitigate any SOL exceedances identified as part of its Real-time monitoring or Real-time Assessment."

FERC also raised the concern that the Pending TOP/IRO Standards do not consider the possibility that additional SOLs could develop or occur in the same-day or Real-time operational time horizon, and therefore would pose an operational risk to the interconnected transmission network.[48] FERC's concern is addressed in proposed Reliability Standard TOP-001-3, where operational responsibilities and actions pertaining to IROLs and SOLs are established for the real-time operational time horizon.

2. TOP Reliability Standards – Issues Requiring Clarification[49]

a. System Models, Monitoring and Tools

FERC raised a concern about NERC's proposed retirement (on redundancy grounds) of TOP Reliability Standards associated with system computer models, monitoring equipment, metering, and analysis tools. FERC stated that

> [m]onitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. . . . [C]ertification is a one-time process that may not adequately assure continual

48 TOP/IRO NOPR at P 55.

49 In addition to the Issues Requiring Clarification discussed below, FERC requested clarification on issues related to Reliability Standard PRC-001. As discussed above, issues related to PRC-001 are being addressed in a separate project.

> operational responsibility would occur if these requirements were in a Reliability Standard.[50]

FERC stated that the retirement of certain requirements in the currently effective IRO and TOP Reliability Standards addressing monitoring and analysis capabilities should not occur before the completion of NERC Project 2009-02.[51]

Proposed Reliability Standard TOP-001-3, Requirements R10 and R11 address this concern by adapting currently effective Reliability Standard IRO-003-2, Requirement R1 to Transmission Operators and Balancing Authorities. Specifically, TOP-001-3, Requirement R10 obligates each Transmission Operator to determine SOL exceedances within its Transmission Operator Area by monitoring facilities and the status of Special Protection Systems, and obtaining and using status, voltages and flow data for facilities and the status of Special Protection Systems outside of its Transmission Operator Area. Similarly, Requirement R11 directs each Balancing Authority to monitor its Balancing Authority Area, including the status of Special Protection Systems that affect generation or load, to maintain generation-load-interchange balance within its Balancing Authority Area and support interconnection frequency. Further, proposed Reliability Standard TOP-001-3, Requirement R13 also adapt currently effective Reliability Standard IRO-008-1, Requirement R2 to the Transmission Operator, requiring each Transmission Operator to perform a Real-time Assessment at least once every 30 minutes.

The proposed changes to Reliability Standard TOP-001-3, Requirements R10, R11 and R13 address FERC's concerns about the retirement of the currently effective IRO and TOP requirements creating gaps on monitoring and analysis capabilities before the completion of

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50 TOP/IRO NOPR at P 60.

51 TOP/IRO NOPR at P 61.

Project 2009-02. Therefore, NERC does not propose a schedule as directed by FERC to complete and implement Project 2009-02 prior to retiring these requirements.[52]

b. Compliance with Reliability Directives

FERC expressed concern with NERC's proposed definition of "Reliability Directive" that could be interpreted as limiting the obligation to comply with Transmission Operator directives in emergencies only.[53] As discussed above, the proposed Reliability Standards used the proposed term "Operating Instruction" to provide additional clarity and specification to the circumstances under which entities must comply with a Transmission Operator's commands.

c. Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

FERC expressed concerns that the Pending TOP/IRO Standards were unclear on the need for including external networks or sub-100 kV facilities in the Operational Planning Analysis conducted by Transmission Operators.[54] The proposed TOP Reliability Standards address this concern as follows. Proposed Reliability Standard TOP-003-3 requires each applicable entity to develop a data specification that would cover its data needs for monitoring and analysis purposes, including non-Bulk Electric System data and external network data deemed necessary by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (see Requirement R1, Part 1.1). Further proposed TOP-003-3, Requirement R5 requires Transmission Operators to supply data to Transmission Operator, thus making it clear that a Transmission Operator may request and receive data from

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52 *Id*.

53 TOP/IRO NOPR at P 64.

54 *Id*. at P 68.

outside of its immediate area. Similar requirements are proposed in IRO-010-2, Requirement R1, Part 1.1 for Reliability Coordinators.

FERC also noted that Order No. 693 contained a directive to modify the TOP Reliability Standards for planned outage coordination to consider sub-100 kV facilities that the registered entity viewed as having a direct impact on Bulk-Power System reliability.[55] The Southwest Blackout Report recommended similar treatment of sub-100 kV facilities and external networks to ensure that Transmission Operators' next-day studies include all external networks and facilities that could affect the reliability of the Bulk-Power System.[56] Proposed Reliability Standard IRO-017-1 addresses outage coordination among the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. Together with the data specification requirements in proposed Reliability Standards TOP-003-3 and IRO-010-2, proposed Reliability Standard IRO-017-1 would help ensure that the outage coordination process established by Reliability Coordinator will consider sub-100 kV facilities that the relevant entities view as having a direct impact on Bulk-Power System reliability.

d. Operating to Respect the Most Severe Single Contingency in Real-Time Operations and Unknown Operating States

In the NOPR, FERC expressed concern with the proposed retirements of TOP-004-2, Requirements R2 and R4, which include "three key rules, the requirements to be ready for the single largest contingency, to move quickly from an 'unknown operating state' to within proven limits, and to determine the cause of SOL violations in all time-frames, including real-time."[57]

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55 *See* TOP/IRO NOPR at P 68 (citing Order No. 693 at P 1624).

56 *See Id*. at P 68 (citing 2011 Southwest Outage Report, recommendation Nos. 2 and 3).

57 *Id*. at P 73. FERC stated that "these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards."

The proposed Reliability Standards maintain the reliability objective of operating to the most severe single contingency by requiring monitoring, notification, and actions to operate within SOLs and IROLs as discussed in preceding sections. Further, the FAC Reliability Standards currently require that SOLs provide a certain level of Bulk Electric System performance for the pre- and post-Contingency state. Additionally, the proposed definitions of "Real-time Assessment" and "Operational Planning Analysis" are strengthened to include Contingency conditions in the evaluations as follows:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

The proposed Reliability Standards require Transmission Operators to plan to operate within SOLs and to initiate Operating Plans to mitigate SOL exceedances. FERC noted that a reliability objective should be to move quickly from an 'unknown operating state' to within proven limits.[58] The standard drafting team considers that, operationally, there always will be limits in service, and an operator should be obligated to adhere to the set of limits in service at the time a situation arises. FERC's concern about an "unknown operating state" is addressed in proposed Reliability Standard TOP-001-3 and the SOL White Paper, attached as Exhibit E hereto, which explains how an SOL exceedance is determined and what entities do upon experiencing such an exceedance. Proposed Reliability Standard TOP-001-3, Requirement R13 specifies that Transmission Operators must perform a Real-time Assessment at least once every

[58] TOP/IRO NOPR at P. 73

30 minutes, which by definition is an evaluation of system conditions to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The Real-time Assessment provides the Transmission Operator with the necessary knowledge of the system operating state to initiate an Operating Plan, as specified in Requirement R14, when necessary to mitigate an exceedance of SOLs, as described in the SOL White Paper. The SOL White Paper provides technical guidance for including timelines in the required Operating Plans to return the system to within prescribed ratings and limits.

Further, proposed Reliability Standard TOP-001-3, Requirements R12 and R13 address this concern by prohibiting a Transmission Operator from operating outside any IROL for a continuous duration exceeding its associated IROL T_v (Requirement R12), and requiring that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes (Requirement R13).

FERC noted that importance of determining 'the cause of SOL violations in all time-frames, including real-time." Proposed Reliability Standard TOP-001-3, Requirement R10 addresses this point by ensuring appropriate action is taken to mitigate an exceedance, but does not specifically require that the cause of the violation must be determined in real-time. Instead, real-time efforts should be focused on resolving the exceedance with causes investigated, analyzed, and determined later and off-line. Pursuant to the revised definition of Real-time Assessment and proposed TOP-001-3, Requirement R13, which requires that a Transmission Operator perform a Real-time Assessment at least every 30 minutes, NERC believes that the Real-time Assessment conducted by Transmission Operators is sufficient for identifying "cause" for operators in Real-time.

Questions posed by FERC with regard to the impact and usefulness of the proposed Real-time Assessment on smaller entities, who often maintain similar reliability based on operator experience,[59] are also addressed by the flexibility that provided in proposed Reliability Standard TOP-001-3, Requirement R13. Requirement R13 requires that a Real-time Assessment be performed every 30 minutes or less, but it does not mandate how it should be done. This requirement would allow smaller entities the flexibility to devise their own methods to comply with the requirement, including contracting with others to provide these services on their behalf.

e. Notification of Emergencies

In the NOPR, FERC identified potential inconsistencies and ambiguities resulting from terminology used in the Pending TOP standards.[60] Proposed Reliability Standard TOP-001-3 uses the defined term "Emergency" in places where FERC identified ambiguity, and applies the term to all operating time horizons. Further, the term Adverse Reliability Impact was eliminated from the proposed standard.

f. Primary Decision-Making Authority for Mitigation of IROLs/SOLs

FERC sought clarification and technical explanation of whether Transmission Operators or Reliability Coordinators have primary responsibility for IROLs.[61] NERC hereby clarifies that the Reliability Coordinator has primary responsibility for IROLs, and the Transmission Operator has primary responsibility for SOLs, although the Reliability Coordinator must provide oversight on SOLs, as well as assistance in mitigating SOLs, as necessary. This split in responsibilities is important for the preservation of reliability within the Bulk Electric System and consistent with

59 TOP/IRO NOPR at P 74.

60 *Id*. at P 80-83.

the NERC functional model. The proposed Reliability Standards were designed to be consistent with these roles.

3. IRO Reliability Standards – Issues to be Addressed

a. Planned Outage Coordination

FERC identified coordination of outages as "a critical reliability function that should be performed by the Reliability Coordinator" that is not adequately addressed in the Pending TOP/IRO Standards.[62] Proposed Reliability Standard IRO-017-1 addresses FERC's NOPR concerns. Under the proposed standard, each Reliability Coordinator is required to develop, implement and maintain an outage coordination process for generation and transmission outages in its Reliability Coordinator Area. Each Transmission Operator and Balancing Authority, in turn, would be required to perform the functions specified in its Reliability Coordinator's process. Further, each Planning Coordinator and Transmission Planner will provide its Planning Assessment to relevant Reliability Coordinators and work together to solve any issues or conflicts with planned outages among the applicable entities. Additionally, proposed Reliability Standard IRO-014-3, Requirement R1, Part 1.4 requires Reliability Coordinators to include the exchange of planned and unplanned outage information to support Operational Planning Analyses and Real-time Assessments in the Operating Procedures, Processes, and Plans for activities that require coordination with adjacent Reliability Coordinators.

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61 *Id*. at P 87.

62 TOP/IRO NOPR at P 90.

4. IRO Reliability Standards – Issues Requiring Clarification

a. Use of a Secure Data Network

FERC sought assurance that the Pending TOP/IRO Standards provided for data exchange and notifications among Reliability Coordinators, Transmission Operators and Balancing Authorities "using a secure mode in a secure environment."[63] Proposed Reliability Standard TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3 specify that security is to be part of a data specification, and to be mutually agreed upon by the applicable registered entities. This proposed change makes clear that the data exchange and notifications among Reliability Coordinators, Transmission Operators, and Balancing Authorities "will be conducted using a secure mode in a secure environment."

b. Reliability Coordinator Monitoring of SOLs and IROLs

FERC expressed concerns with proposed changes to the obligation of Reliability Coordinators to monitor SOLs in the currently effective IRO Reliability Standards.[64] The proposed Reliability Standards maintain the obligations for Reliability Coordinators to monitor SOLs. Specifically, proposed Reliability Standard IRO-002-4, Requirement R3 requires each Reliability Coordinator to monitor facilities, Special Protection Systems, and necessary non-Bulk Electric System facilities in order to identify SOL and IROL exceedances within its Reliability Coordinator Area.

E. Consideration of Outstanding FERC Directives

In developing the proposed Reliability Standards, the standard drafting team also addressed outstanding FERC directives relevant to the proposed Reliability Standards. Exhibit H

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63 TOP/IRO NOPR at P 94.

64 *Id*. at P 96.

hereto provides a list of these outstanding directives and a description of the manner in which the standard drafting team addressed these directives. The following is a brief discussion of how the proposed Reliability Standards address the notable outstanding directives.

1. Outstanding Directives Related to the IRO Reliability Standards

- FERC directed NERC to consider clarifying the requirement in IRO-001-1 that entities comply with a Reliability Coordinator's directive "unless such actions would violate safety, equipment or regulatory or statutory requirements."[65] As discussed above, that requirement is carried forward in proposed Reliability Standard IRO-001-4. The standard drafting team clarified during the development of the standard that the term "safety" should be read broadly to encompass the safety of both personnel and equipment and that no additional wording is needed.

- FERC also directed NERC to consider stakeholder comments regarding the establishment of a chain of command so that, for example, if a Generator Operator receives conflicting instructions from a Balancing Authority and a Transmission Operator, it can determine which instruction governs.[66] The standard drafting team concluded that no additional medications to the proposed Reliability Standards are necessary. If Generator Operator receives conflicting Operating Instructions, the Generator Operator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.

- FERC also directed NERC to consider stakeholder comments that Reliability Standard IRO-001-1 fails to address the operational limitations of qualifying facilities ("QFs") because QFs have contractual obligations to provide thermal energy to their industrial hosts and can only be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.[67] The standard drafting team concluded that no modifications to the proposed Reliability Standards were necessary because while a Reliability Coordinator can direct a QF to act in accordance with an Operating Instructions, the proposed Reliability Standards do not require a QF to comply if it would violate the QFs regulatory or statutory requirements.

- FERC directed NERC to modify Reliability Standard IRO-002-1 to require a minimum set of tools that must be made available to the Reliability Coordinator.[68] This directive was beyond the scope of Project 2014-03 and is being addressed in a separate standards development project (Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities).

65 Order No. 693 at P 897.

66 *Id*. at P 897.

67 *Id*.

68 *Id*. at P 905.

- FERC directed NERC to develop a modification to Reliability Standard IRO-003-1 to create criteria to define the term "critical facilities" in a Reliability Coordinator's area and its adjacent systems.[69] The proposed Reliability Standards no longer use the term "critical facilities." As discussed above, proposed Reliability Standard IRO-010-2 provides a mechanism for Reliability Coordinators to obtain data necessary to perform its reliability tasks, obviating the need for specific criteria for determining critical facilities.

- FERC directed NERC to modify Reliability Standard IRO-004-1 to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency.[70] As described above, this issue is addressed in proposed Reliability Standards IRO-008-2 and TOP-002-4, as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. In short, SOLs must be controlled according to the Operating Plan, which is set up on time-based facility ratings. IROLs are controlled to the IROL Tv, which by definition is always less than 30 minutes. Reliability Standard IRO-009-1, also addresses this issue.

- FERC directed NERC to include a requirement for the Reliability Coordinator to assess and approve actions that have impacts beyond the area views of Transmission Operators or Balancing Authorities, including how to determine whether an action needs to be assessed by the Reliability Coordinator.[71] Proposed Reliability Standard IRO-008-2, Requirements R2 and R5 address this directive by requiring Reliability Coordinators to (1) have coordinated Operating Plans for next-day operations, and (2) notify impacted Transmission Operators, Balancing Authorities and other Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

- FERC directed NERC to provide clarification in proposed standards that Reliability Coordinators and Transmission Operators direct control actions of entities in their respective areas to respect System Operating Limits and Interconnection Reliability Operating Limits.[72] Proposed Reliability Standard IRO-001-4 Requirement R1 addresses this clarification in the case of the Reliability Coordinator as discussed above. (TOP-001-3 Requirement R1 addresses this clarification in the case of the Transmission Operator).

- In Order No. 693, FERC also directed NERC to include the Reliability Coordinator as an applicable entity in Reliability Standard VAR-001-1 given its role as the highest level of authority overseeing the reliability of the Bulk-Power System.[73] Although the directive

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69 Order No. 693 at P 914.

70 *Id*. at P 935.

71 *Id*. at P 525.

72 *Id*. at P 950.

73 *Id*. at P 1855.

related to the VAR standards, because the IRO standards address the Reliability Coordinator's oversight of Bulk-Power System facilities, the standard drafting team concluded that this directive is addressed in proposed Reliability Standard IRO-002-4, Requirement R3, which requires the Reliability Coordinator to monitor facilities, which would include voltage and reactive power resources.

- Similarly, FERC directed NERC to develop a modification to INT-006-1 that makes it applicable to Reliability Coordinators and Transmission Operators, requiring them to review energy interchange transactions from the wide-area and local area reliability viewpoints, respectively, and, where their review indicates a potential detrimental reliability impact, communicate to the sink Balancing Authorities necessary transaction modifications before implementation.[74] Proposed Reliability Standard IRO-008-2 addresses this directive by requiring Reliability Coordinators to perform an Operational Planning Analysis, which requires Reliability Coordinators to consider Interchange, and develop a plan to address any problems. Similar requirements exist for the Transmission Operator in proposed Reliability Standard TOP-002-3.

- Directives pertaining to Reliability Standard PRC-001[75] are being addressed in a separate project to revise that standard.

2. Outstanding Directives Related to the TOP Reliability Standards

- FERC directed to NERC to modify TOP-001-1 to define the term "emergency."[76] Proposed TOP-001-3 uses the defined term "Emergency" to improve clarity. The standard drafting team concluded that criteria for entering operating states belong in EOP standards, as noted by FERC in Order 693.[77] Currently enforceable Reliability Standard EOP-002-3.1 - Capacity and Energy Emergencies and proposed Reliability Standard EOP-011-1 contain responsibilities.

- FERC directed to NERC to consider stakeholder comments to require the Transmission Operator to notify the Reliability Coordinator or the Balancing Authority that it is removing facilities from service.[78] This directive is addressed in proposed Reliability Standard TOP-001-3, Requirement R8, which requires Transmission Operators to inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

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74 Order No. 693 at P 866.

75 *Id*. at P 1449.

76 *Id*. at P 1585.

77 *Id*. at P 560.

78 *Id*. at P 1588.

- FERC directed revisions to TOP-002-2 and TOP-005-1 to deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.[79] As discussed above, proposed Reliability Standards IRO-010-2 and TOP-003-3 address security of data.

- FERC directed revisions to TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.[80] As IROLs are the responsibility of the Reliability Coordinator, this issue is addressed in proposed Reliability Standard IRO-008-2 and Reliability Standard IRO-009-1, as discussed above.

- FERC directed revisions to TOP-002-2 to require next-day analysis of minimum voltages at nuclear power plants auxiliary power busses.[81] This issue is addressed through proposed Reliability Standards IRO-010-2 and TOP-003-3, which provide Reliability Coordinators and Transmission Operators, respectively, a mechanism to acquire all of the data necessary for them to fulfill their reliability functions including non-Bulk Electric System data, as necessary. Next-day analysis is performed using Operational Planning Analysis.

- FERC directed revisions to TOP-002-2 to also require simulation contingencies to match what will actually happen in the field.[82] The standard drafting team revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly to require Contingencies to match field conditions.

- FERC directed NERC to revise TOP-003-0 to require the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of available transmission capability calculations.[83] Proposed Reliability Standard IRO-017-1 addresses this directive by requiring Reliability Coordinators to develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

- FERC also directed NERC to revise TOP-003-0 to incorporate an appropriate lead-time for planned outages.[84] The standard drafting team determined that such a requirements is not necessary and could potentially conflict with existing rules in organized markets.

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79 Order No. 693 at PP 1608, 1651.

80 *Id*. at P 1608.

81 *Id*.

82 *Id*.

83 *Id*. at P 1620.

84 *Id*. at P 1621.

Nevertheless, pursuant to proposed Reliability Standard IRO-017-1, a Reliability Coordinator could include lead times in its process.

- FERC directed NERC to consider whether to include breaker outages within the meaning of facilities that are subject to advance notice for planned outages.[85] Pursuant to IRO-017-1, a Reliability Coordinator could include breakers in its outage coordination process.

- FERC also directed modifications to TOP-003-0 to require that any facility below the thresholds in Requirement R1 of that standard that, in the opinion of the Transmission Operator, Balancing Authority, or Reliability Coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to planned outage coordination.[86] Under proposed Reliability Standards IRO-010-2 and TOP-003-3, the Reliability Coordinator and Transmission Operator have a mechanism to obtain the data necessary to perform their reliability tasks, including identifying the appropriate facilities for outage coordination.

- FERC directed modification to TOP-004-1 to require that the system be restored to respect proven limits as soon as possible taking no more than 30 minutes.[87] This directive is addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment, and the requirements in proposed Reliability Standard TOP-004-2 for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances.

- FERC also directed revisions to TOP-004-1 to explicitly incorporate the interpretation of "multiple outages" as multiple element outages resulting from high-risk conditions.[88] The standard drafting team concluded that Reliability Standard EOP-001-2.1b, which covers emergency operations planning, already addresses this directive. In addition, Reliability Standard FAC-011-2 and FAC-014-2 includes specific requirements for dealing with multiple contingencies.

- FERC also directed NERC to consider stakeholder comments that TOP-004-1, Requirement R2 should be revised to include frequency monitoring.[89] This directive is addressed by proposed Reliability Standards IRO-010-2 and TOP-003-3, which provide Reliability Coordinators and Transmission Operators a mechanism to obtain data on frequency, voltages, real and reactive power flows, and any other data that the entity needs.

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85 Order No. 693 at P 1622.

86 *Id*. at P 1624.

87 *Id*. at P 1636.

88 *Id*. at P 1638.

89 *Id*. at P 1639.

- FERC directed revisions to TOP-005-1 regarding the operational status of special protection systems and power system stabilizers.[90] The standard drafting team addressed this directive in proposed Reliability Standards IRO-010-2 and TOP-003-3 and in revising the definitions of Operational Planning Analysis and Real-time Assessments. Proposed Reliability Standards IRO-010-2 and TOP-003-3 specifically include a requirement to have provisions for notification of current Protection System and Special Protection System status or degradation.

- FERC directed revisions to TOP-005-1 to add a requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.[91] This directive was beyond the scope of Project 2014-03 and will be addressed in a future standards development project (Project 2009-02 Real-time Monitoring and Analysis Capabilities).

- FERC directed NERC to clarify the meaning of "appropriate technical information" concerning protective relays as used in TOP-006-1.[92] That term is not used in the proposed Reliability Standards. To address concerns about the status of protection systems, the standard drafting team incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards (i.e., proposed Reliability Standards IRO-010-2 and TOP-003-3).

- FERC directed NERC to consider the Nuclear Energy Regulatory Commission's comments related to nuclear power plant voltage requirements.[93] Under proposed Reliability Standards TOP-002-3 and TOP-001-3, applicable entities must study minimum voltage limits, including those at nuclear plants.

In addition to the directives addressed by the standards drafting team, discussed above, NERC also notes that it resolved two directives from Order No. 748[94] that relate to the issues addressed by the proposed Reliability Standards. First, FERC directed the NERC Reliability Coordinator Working Group to consider whether the need exists to refine the delineation of responsibilities between the Reliability Coordinator and Transmission Operator for analyzing

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90 Order No. 693 at P 1648.

91 *Id*. at PP 1660, 1875.

92 *Id*. at P 1665.

93 *Id*. at P 1673.

94 *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

certain "grid-impactive" SOLs that are of interest to the Reliability Coordinator.[95] Second, FERC directed the NERC Reliability Coordinator Working Group to consider whether there is a need for reliability coordinators to have action plans developed and implemented with respect to certain "grid-impactive" SOLs that are of interest to the Reliability Coordinator.[96]

The working group, which included participation from the NERC Operating Committee and stakeholders, concluded that there was no need to create another category between IROL and SOL called "grid-impactive" SOLs. The working group determined that such a category could not be clearly defined and consequently did not support changes to the currently effective IRO standards. In addition to the working group action, the directives are addressed by proposed IRO-008-2 Requirements R1 and R2, which require the Reliability Coordinator to (1) analyze both SOLs and IROLs, as discussed above, and (2) must have a coordinated operating plan to address potential SOL and IROL exceedances which considers the operating plans provided by the Transmission Operators.

F. Enforceability of Proposed Reliability Standards

The proposed Reliability Standards also include measures that support each requirement by clearly 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.[97]

The proposed Reliability Standards also 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

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[95] Order No. 748 at P 44.

[96] *Id*. at P 55.

[97] Order No. 672 at P 327.

NERC and FERC guidelines related to their assignment. Exhibit J provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

Respectfully submitted,

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Date: March 25, 2015

EXHIBITS A—B and D – L

(Available on the NERC Website at

http://www.nerc.com/FilingsOrders/ca/Canadian%20Filings%20and%20Orders%20DL/TOP-IRO%20exhibits.pdf)

EXHIBIT C

Reliability Standards Criteria

The discussion below explains how the proposed Reliability Standards meet or exceed 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.**

The proposed Reliability Standards achieve the specific reliability goal of addressing the roles and responsibilities of Reliability Coordinators, Transmission Operators, and Balancing Authorities with respect to planning and operating the Bulk Electric System. The proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the Bulk Electric System is operated within limits while enhancing situational awareness and strengthening operations planning.

The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. Among other things, the proposed Reliability Standards help to ensure that Reliability Coordinators and Transmission Operators work together, and with other functional entities, to operate the Bulk Electric System within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"). SOLs and IROLs are vital concepts in NERC's Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

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. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

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 the proposed Reliability Standards comport with NERC and FERC guidelines related to their assignment, as discussed further in Exhibit J. The assignment of the severity level for each VSL is consistent with the corresponding requirement. 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. The proposed Reliability Standards clearly articulate the reliability objectives that applicable entities must meet.

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 proposed Reliability Standards contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standards help ensure that entities coordinate efforts to plan and operate the Bulk Electric System in a reliable manner under normal and abnormal conditions.

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 impact on competition. The proposed Reliability Standards require the same performance by each applicable entity. The 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 standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation periods will allow applicable entities adequate time to meaningfully implement the requirements. The proposed effective dates are explained in the proposed Implementation Plan, 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. Exhibit K includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment 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.

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.