DEMANDE DE LA NERC RELATIVE

AU PROJET DE RÉVISION DES NORMES

DE FAMILLE TOP ET IRO ET

ORDONNANCE NO 817 DE LA FERC

(EN ANGLAIS)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED TRANSMISSION OPERATIONS AND INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS

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Pursuant to Section 215(d)(1) of the Federal Power Act[1] and Section 39.5[2] of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval the following nine proposed Reliability Standards (Exhibit A):[4]

- 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).

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[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2014).

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

[4] 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.

NERC requests that the Commission approve the proposed Reliability Standards and find that each is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed further below, the proposed Reliability Standards replace the Reliability Standards currently pending with the Commission in Docket Nos. RM12-12-000, RM13-14-000 and RM13-15-000 (the "Pending TOP/IRO Standards).[5]

NERC also requests approval 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 requests 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);

[5] Concurrent with this filing, NERC is submitting a motion to withdraw the Reliability Standards pending Commission approval in those dockets. *Notice of Withdrawal of the North American Electric Reliability Corporation*, Docket Nos. RM13-12-000, RM13-14-000, and RM13-15-000 (Mar. 18, 2015).

- 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).

As required by Section 39.5(a) of the Commission's regulations,[6] this Petition 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 criteria identified by the Commission in Order No. 672[7] (Exhibit C).

This Petition is organized as follows: Section I of the Petition presents an executive summary of the proposed Reliability Standards. Section II of the Petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides background on the regulatory structure governing the Reliability Standards approval process, as well as information on the development of the proposed Reliability Standards. Section IV of the Petition 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 FERC and NERC report on the 2011 Arizona-Southern California outages ("Southwest Outage Report") (*see also* Exhibit F),[8]

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6 18 C.F.R. § 39.5(a) (2014).

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

8 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.

- concerns raised by the Commission 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),[9] 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 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

[9] *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").

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.

For the reasons discussed herein, NERC respectfully requests that the Commission approve the proposed Reliability Standards, the proposed revised definitions, and the proposed retirements.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[10]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[12] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[13] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[14] of the Commission's regulations requires the ERO to file with the

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10 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

11 16 U.S.C. § 824o (2012).

12 *Id.* § 824(b)(1).

13 *Id.* § 824o(d)(5).

14 18 C.F.R. § 39.5(a).

Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[15] and Section 39.5(c)[16] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards and definitions were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[17] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[18] In its order certifying NERC as the Commission's Electric Reliability Organization, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability

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15 16 U.S.C. § 824o(d)(2).

16 18 C.F.R. § 39.5(c)(1).

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

18 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.

Standards[19] and thus satisfies certain of the criteria for approving Reliability Standards.[20] 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 Commission for approval.

C. 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 filed on April 5, 2013 in Docket No. RM13-12-000. 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 filed on April 16, 2013, in Docket No. RM13-14-000. These Reliability Standards were intended to replace the eight currently effective TOP Reliability Standards.[21]

- *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 filed on April 16, 2013, in Docket No. RM13-15-000. These four Reliability Standards were intended to replace six currently effective IRO Reliability 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, the Commission issued the TOP/IRO NOPR, proposing to approve proposed Reliability Standard TOP-006-3 but remand the other Pending TOP/IRO Standards. A

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19 ERO Certification Order at P 250.

20 Order No. 672 at PP 268, 270.

21 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 requesting withdrawal of its request for approval 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.

summary of the Commission's concerns raised in the TOP/IRO NOPR are included in Section IV as well as Exhibit G.

In response to the TOP/IRO NOPR, on December 20, 2013, NERC filed a motion requesting that the Commission defer action on the Pending TOP/IRO Standards, until January 31, 2015, to allow NERC time to consider the reliability concerns raised by the Commission and revise the Pending TOP/IRO Standards as necessary.[22] The Commission granted that motion on January 14, 2014.[23] NERC has been providing the Commission quarterly updates on the status of its standards development process to revise the Pending TOP/IRO Standards. In its quarterly report for the fourth quarter of 2014, filed January 2, 2015, NERC informed the Commission that it needed additional time to obtain NERC Board of Trustees ("Board") adoption of proposed Reliability Standard TOP-001-3 at the Board's regularly scheduled meeting on February 12, 2015.

D. 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 Commission 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[24] and Project 2007-03 Real-time Operations.[25]

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22 *Motion of the North American Electric Reliability Corporation to Defer Action*, Docket No. RM13-12-000 (December 20, 2013).

23 *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards,* 146 FERC ¶ 61,023 (2014).

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

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

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").[26]

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 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 FOR APPROVAL

As discussed in Exhibit C, the proposed Reliability Standards and definitions satisfy the Commission's criteria in Order No. 672 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,[27] the Southwest Outage Report, the IERP Report, the NERC Operating Committee consideration of the IERP report (Exhibit I), and the Commission'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

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26 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.

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

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 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.[28]

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)"

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[28] *See* Order No. 693 at P 1582 "the reliability coordinator is the highest authority in matters affecting reliability of the Bulk-Power System."

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 the Commission has noted, during deteriorating system conditions, an SOL can rapidly degrade into an IROL.[29] 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 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.[30]

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

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[29] TOP/IRO NOPR at P 52.

[30] *See* i*d*. As the Commission 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.*

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},[31] 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 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.[32]

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[31] 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."

[32] 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

Additionally, the proposed Reliability Standards now use the proposed NERC Glossary term "Operating Instruction"[33] 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.

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

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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.

[33] The defined term "Operating Instruction" was developed along with proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocol) and is currently pending before the Commission in Docket No. RM14-13-000. *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards COM-001-2 and COM-002-4*, Docket No. RM14-13-000 (May 14, 2014). On September 18, 2014, the Commission 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.

Model.[34] 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.

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.

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

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 Commission-approved 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. <u>Proposed Definitions</u>

NERC submits for Commission approval 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 is currently pending Commission approval in Docket No. RM14-13-000, is used in proposed Reliability Standards TOP-001-3 and IRO-001-4.[35] 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.

[35] The definition for "Operating Instruction" was developed and submitted for Commission approval along with the proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocols). As noted above, on September 18, 2014, the Commission 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.

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 petition, 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 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.[36]

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 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

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

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 the Commission's concerns that the Pending TOP/IRO Standards did not have sufficient requirements for real-time monitoring.[37]

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.

[37] TOP/IRO NOPR at P 60.

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.[38]

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.[39] 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.

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38 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.

39 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.

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.

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

Commission-approved 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.[40]

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

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

- 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.[41] 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.

[41] 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."

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

- *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.[42] 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

[42] 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."

outages and leaving approximately 2.7 million customers without power ("2011 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.[43]

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.[44]

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.[45] The Southwest Outage Report findings are divided into eight

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43 Southwest Outage Report at 1.

44 *Id*. at 5.

45 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.

categories, [46] 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.[47] 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 petition.[48] Below is a short description of each applicable finding and recommendation identified in the Southwest Outage Report,[49] 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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[46] 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.

[47] *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.

[48] *Id.*

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

1. Operations Planning

Eight findings in the Southwest Outage Report relate to operations planning.[50] 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.

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[50] 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.[51]

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 process that will

[51] 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.

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[52] 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 addresses

[52] 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.

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.[53] 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 procedures

[53] *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

and training[54] 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

[54] The training issue falls outside of the scope of Project 2014-03.

5C to the NERC Rules of Procedure.[55] 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.[56] 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 Commission-approved 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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[55] *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).

[56] In approving the exception process, the Commission 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. <u>Interconnection Reliability Operating Limit Derivations</u>

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. <u>Protection Systems</u>

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.[57] 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.

D. Consideration of TOP/IRO NOPR Concerns

In its TOP/IRO NOPR, the Commission expressed certain concerns regarding the Pending TOP/IRO Standards and proposed to remand those standards for further consideration in NERC's

[57] 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 3, 2015 NERC filed a petition for approval of revisions to the definition of "*Remedial Action Scheme*" ("RAS"), which proposes to eliminate the defined term Special Protection System. See RM15-13-000. Proposed TOP/IRO standards will be modified as necessary based on the Commission's action in response to NERC's petition in RM15-13-000.

standards development process.[58] The Commission 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 the Commission'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

The Commission expressed concern that the Pending TOP/IRO Standards lacked a requirement for Transmission Operators to analyze and operate within all SOLs.[59] Specifically, the Commission 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.[60] The Commission maintained that this limitation would reduce system reliability and cause negative consequences external to the Transmission Operator's area.[61] The Commission also expressed the concern that deteriorating system conditions may result in an SOL rapidly degrading into an IROL. The Commission noted further that limiting the analysis to non-IROL SOLs identified internally by the Transmission Operator may "reduce system reliability because operators have less situational awareness of the system and conditions."[62]

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58 TOP/IRO NOPR at PP 42-99.

59 *Id*. at P 42.

60 *Id*.

61 *Id*. at PP 42, 51.

62 *Id*. at P 52.

The proposed Reliability Standards address the Commission'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 the Commission's concern that the previously-proposed Reliability Standards limited "non-IROL SOLs" to only those internally identified by the Transmission Operator.

The Commission 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."[63] The Commission 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.[64]

To address the Commission's concerns,[65] proposed Reliability Standard TOP-002-4 requires, among other things, that Transmission Operators have: (1) 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; and (2) an Operating Plans for next-day operations to address potential SOL exceedances identified as a result of its Operational Planning

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63 TOP/IRO NOPR at P 54.

64 *Id*. at P 54.

65 *Id*.

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."

The Commission 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.[66] The Commission'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[67]

a. System Models, Monitoring and Tools

The Commission 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. The Commission 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 operational responsibility would occur if these requirements were in a Reliability Standard.[68]

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[66] TOP/IRO NOPR at P 55.

[67] In addition to the Issues Requiring Clarification discussed below, the Commission 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.

[68] TOP/IRO NOPR at P 60.

The Commission 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.[69]

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 the Commission's concerns about the retirement of the currently effective IRO and TOP requirements creating gaps on monitoring and analysis capabilities before the completion of Project 2009-02. Therefore, NERC does not propose a schedule as directed by the Commission to complete and implement Project 2009-02 prior to retiring these requirements.[70]

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69 TOP/IRO NOPR at P 61.

70 *Id*.

b. Compliance with Reliability Directives

The Commission 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.[71] 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

The Commission 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.[72] 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 outside of its immediate area. Similar requirements are proposed in IRO-010-2, Requirement R1, Part 1.1 for Reliability Coordinators.

[71] TOP/IRO NOPR at P 64.

[72] *Id*. at P 68.

The Commission 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.[73] 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.[74] 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, the Commission 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."[75] 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

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

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

[75] *Id*. at P 73. The Commission 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."

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. The Commission noted that a reliability objective should be to move quickly from an 'unknown operating state' to within proven limits.[76] 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. The Commission'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 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

[76] TOP/IRO NOPR at P. 73

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).

The Commission 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 the Commission 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,[77] 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, the Commission identified potential inconsistencies and ambiguities resulting from terminology used in the Pending TOP standards.[78] Proposed Reliability Standard TOP-001-3 uses the defined term "Emergency" in places where the Commission 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

The Commission sought clarification and technical explanation of whether Transmission Operators or Reliability Coordinators have primary responsibility for IROLs.[79] 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

[77] TOP/IRO NOPR at P 74.

[78] *Id*. at P 80-83.

[79] *Id*. at P 87.

and consistent with 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

The Commission 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.[80] Proposed Reliability Standard IRO-017-1 addresses the Commission'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.

[80] TOP/IRO NOPR at P 90.

4. IRO Reliability Standards – Issues Requiring Clarification

a. Use of a Secure Data Network

The Commission 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."[81] 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

The Commission expressed concerns with proposed changes to the obligation of Reliability Coordinators to monitor SOLs in the currently effective IRO Reliability Standards.[82] 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 Commission Directives

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

81 TOP/IRO NOPR at P 94.

82 *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. <u>Outstanding Directives Related to the IRO Reliability Standards</u>

- The Commission 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."[83] 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.

- The Commission 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.[84] 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.

- The Commission 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.[85] 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.

- The Commission 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.[86] This directive was beyond the scope of Project 2014-03 and is being addressed in a separate

83 Order No. 693 at P 897.

84 *Id*. at P 897.

85 *Id*.

86 *Id*. at P 905.

standards development project (Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities).

- The Commission 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.[87] 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.

- The Commission 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.[88] 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. Commission-approved Reliability Standard IRO-009-1, also addresses this issue.

- The Commission 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.[89] 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.

- The Commission 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. [90] 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, the Commission 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.[91]

[87] Order No. 693 at P 914.

[88] *Id*. at P 935.

[89] *Id*. at P 525.

[90] *Id*. at P 950.

[91] *Id*. at P 1855.

Although the directive 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, the Commission 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.[92] 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[93] are being addressed in a separate project to revise that standard.

2. <u>Outstanding Directives Related to the TOP Reliability Standards</u>

- The Commission directed to NERC to modify TOP-001-1 to define the term "emergency."[94] 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 the Commission in Order 693.[95] Currently enforceable Reliability Standard EOP-002-3.1 - Capacity and Energy Emergencies and proposed Reliability Standard EOP-011-1 contain responsibilities.

- The Commission 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.[96] 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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92 Order No. 693 at P 866.

93 *Id*. at P 1449.

94 *Id*. at P 1585.

95 *Id*. at P 560.

96 *Id*. at P 1588.

- The Commission 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.[97] As discussed above, proposed Reliability Standards IRO-010-2 and TOP-003-3 address security of data.

- The Commission 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.[98] As IROLs are the responsibility of the Reliability Coordinator, this issue is addressed in proposed Reliability Standard IRO-008-2 and Commission-approved Reliability Standard IRO-009-1, as discussed above.

- The Commission directed revisions to TOP-002-2 to require next-day analysis of minimum voltages at nuclear power plants auxiliary power busses.[99] 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.

- The Commission directed revisions to TOP-002-2 to also require simulation contingencies to match what will actually happen in the field.[100] The standard drafting team revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly to require Contingencies to match field conditions.

- The Commission 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.[101] 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.

- The Commission also directed NERC to revise TOP-003-0 to incorporate an appropriate lead-time for planned outages.[102] The standard drafting team determined that such a requirements is not necessary and could potentially conflict with existing rules in

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97 Order No. 693 at PP 1608, 1651.

98 *Id*. at P 1608.

99 *Id*.

100 *Id*.

101 *Id*. at P 1620.

102 *Id*. at P 1621.

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

- The Commission directed NERC to consider whether to include breaker outages within the meaning of facilities that are subject to advance notice for planned outages.[103] Pursuant to IRO-017-1, a Reliability Coordinator could include breakers in its outage coordination process.

- The Commission 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.[104] 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.

- The Commission 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.[105] 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.

- The Commission also directed revisions to TOP-004-1 to explicitly incorporate the interpretation of "multiple outages" as multiple element outages resulting from high-risk conditions.[106] The standard drafting team concluded that Commission-approved Reliability Standard EOP-001-2.1b, which covers emergency operations planning, already addresses this directive. In addition, Commission-approved Reliability Standard FAC-011-2 and FAC-014-2 includes specific requirements for dealing with multiple contingencies.

- The Commission also directed NERC to consider stakeholder comments that TOP-004-1, Requirement R2 should be revised to include frequency monitoring.[107] 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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[103] Order No. 693 at P 1622.

[104] *Id*. at P 1624.

[105] *Id*. at P 1636.

[106] *Id*. at P 1638.

[107] *Id*. at P 1639.

- The Commission directed revisions to TOP-005-1 regarding the operational status of special protection systems and power system stabilizers.[108] 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.

- The Commission 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.[109] 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).

- The Commission directed NERC to clarify the meaning of "appropriate technical information" concerning protective relays as used in TOP-006-1.[110] 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).

- The Commission directed NERC to consider the Nuclear Energy Regulatory Commission's comments related to nuclear power plant voltage requirements.[111] 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[112] that relate to the issues addressed by the proposed Reliability Standards. First, the Commission 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

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108 Order No. 693 at P 1648.

109 *Id*. at PP 1660, 1875.

110 *Id*. at P 1665.

111 *Id*. at P 1673.

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

analyzing certain "grid-impactive" SOLs that are of interest to the Reliability Coordinator.[113] Second, the Commission 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.[114]

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.[115]

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 NERC and

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113 Order No. 748 at P 44.

114 *Id*. at P 55.

115 Order No. 672 at P 327.

Commission 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.

V. CONCLUSION

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

- the proposed Reliability Standards and associated elements included in Exhibit A;
- the proposed revised definitions to be incorporated into the NERC Glossary, included in Exhibit A; and
- the proposed Implementation Plan, including the noted retirements, included in Exhibit B.

Respectfully submitted,

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Date: March 18, 2015

153 FERC ¶ 61,178
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-16-000, Order No. 817]

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

(Issued November 19, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission approves revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation, which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The Commission also directs NERC to make three modifications to the standards within 18 months of the effective date of the final rule.

EFFECTIVE DATE: This rule will become effective **[60 days after publication in the FEDERAL REGISTER].**

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SUPPLEMENTARY INFORMATION:

153 FERC ¶ 61,178
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards — Docket No. RM15-16-000

ORDER NO. 817

FINAL RULE

(Issued November 19, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements and improve efficiency by

[1] 16 U.S.C. 824o (2012).

incorporating the necessary requirements from the eight currently-effective TOP Reliability Standards into three comprehensive Reliability Standards. Further, the standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the proposed standards that apply to transmission operators for the TOP standards and reliability coordinators for the IRO standards. Thus, we conclude that there are benefits to clarifying and bringing efficiencies to the TOP and IRO Reliability Standards, consistent with the Commission's policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[2]

2. The Commission also finds that NERC has adequately addressed the concerns raised by the Commission in the Notice of Proposed Rulemaking issued in November 2013 concerning the proposed treatment of system operating limits (SOLs) and interconnection reliability operating limits (IROLs) and concerns about outage coordination.[3] Further, the Commission approves the definitions for operational

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

[3] Monitoring System Conditions - *Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards*, Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013) (Remand NOPR). Concurrent with filing the proposed TOP/IRO standards in the immediate proceeding, NERC submitted a motion to withdraw the earlier petition that was the subject of the Remand NOPR. No protests to the motion were filed and the petition was withdrawn pursuant to 18 CFR 385.216(b).

planning analysis and real-time assessment, the implementation plans and the violation severity level and violation risk factor assignments. However, the Commission directs NERC to make three modifications to the standards as discussed below within 18 months of the effective date of this Final Rule.

3. We also address below the four issues for which we sought clarifying comments in the June 18, 2015, Notice of Proposed Rulemaking (NOPR) proposing to approve the TOP and IRO Reliability Standards: (A) possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (D) data exchange capabilities. In addition we address other issues raised by commenters.

I. Background

A. Regulatory Background

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[4] Once approved, the Reliability Standards may be enforced by the ERO

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[4] 16 U.S.C. 824o(c) and (d).

subject to Commission oversight, or by the Commission independently.[5] In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[6]

5. The Commission approved the initial TOP and IRO Reliability Standards in Order No. 693.[7] On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.[8] Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had "removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these

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[5] *See id.* 16 U.S.C. 824o(e).

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[7] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 508, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards. *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

[8] On April 5, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources.

aspects in the proposed standards."[9] The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

B. NERC Petition

6. On March 18, 2015, NERC filed a petition with the Commission for approval of the proposed TOP and IRO Reliability Standards.[10] As explained in the Petition, the proposed Reliability Standards consolidate many of the currently-effective TOP and IRO Reliability Standards and also replace the TOP and IRO Reliability Standards that were the subject of the Remand NOPR. NERC stated that the proposed Reliability Standards include improvements over the currently-effective TOP and IRO Reliability Standards in (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. NERC stated that the proposed TOP and IRO Reliability Standards address outstanding Commission directives relevant to the proposed TOP and

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[9] Remand NOPR, 145 FERC ¶ 61,158 at P 4.

[10] The TOP and IRO Reliability Standards are not attached to the Final Rule. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket No. RM15-16 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

IRO Reliability Standards. NERC stated that 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. NERC explained that the proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. NERC contended that 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 SOLs and IROLs.[11] NERC also provided explanations of how the proposed Reliability Standards address the reliability issues identified in the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations ("2011 Southwest Outage Blackout Report").

7. NERC proposed three TOP Reliability Standards to replace the existing suite of TOP 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, with certain requirements

[11] The NERC Glossary of Terms defines IROL 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." In turn, NERC defines SOL as "[t]he 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…."

applying to the roles and responsibilities of the balancing authority. Among other things, NERC stated that the proposed revisions to the TOP Reliability Standards help ensure that transmission operators plan and 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. NERC stated that, 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 reliability coordinators 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.

8. NERC also proposed revised definitions for "operational planning analysis" and "real-time assessment." For all standards except proposed Reliability Standards TOP-003-3 and IRO-010-2, NERC proposed the effective date to be the first day of the first calendar quarter twelve months after Commission approval. According to NERC's implementation plan, for proposed TOP-003-3, all requirements except Requirement R5 will become effective on the first day of the first calendar quarter nine months after the date that the standard is approved. For proposed IRO-010-2, Requirements R1 and R2 would become effective on the first day of the first calendar quarter that is nine months after the date that the standard is approved. Proposed TOP-003-3, Requirement R5 and

IRO-010-2, Requirement R3 would become effective on the first day of the first calendar quarter twelve months after the date that the standard is approved. The reason for the difference in effective dates for proposed TOP-003-3 and IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests from their reliability coordinators, transmission operators, and/or balancing authorities.

C. Notice of Proposed Rulemaking

9. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking proposing to approve the TOP and IRO Reliability Standards pursuant to FPA section 215(d)(2), along with the two new definitions referenced in the proposed standards, the assigned violation risk factors and violation severity levels, and the proposed implementation plan for each standard.[12]

10. In the NOPR, the Commission explained that the proposed TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The Commission also proposed to find that NERC has adequately addressed the concerns raised by the Remand NOPR issued in November 2013.

[12] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 151 FERC ¶ 61,236 (2015) (NOPR).

11. In the NOPR, the Commission also discussed the following specific matters and asked for further comment: (A) possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (D) data exchange capabilities.

12. Timely comments on the NOPR were filed by: NERC; Arizona Public Service Company (APS), Bonneville Power Administration (BPA), Dominion Resources Services, Inc. (Dominion), the Edison Electric Institute (EEI); Electric Reliability Council of Texas, Inc. (ERCOT), Independent Electricity System Operator (IESO), ISO/RTOs,[13] International Transmission Company (ITC); Midcontinent Independent System Operator, Inc., Northern Indiana Public Service Company (NIPSCO), Occidental Energy Ventures, LLC (Occidental), Peak Reliability (Peak), and Transmission Access Policy Study Group (TAPS).

II. Discussion

13. Pursuant to section 215(d) of the FPA, we adopt our NOPR proposal and approve NERC's revisions to the TOP and IRO Reliability Standards, including the associated definitions, violation risk factors, violation severity levels, and implementation plans, as just, reasonable, not unduly discriminatory or preferential and in the public interest. We

[13] ISO/RTOs include Independent Electricity System Operator, ISO New England Inc., Midcontinent Independent System Operator, New York Independent System Operator, Inc., PJM Interconnection LLC, and Southwest Power Pool, Inc.

note that all of the commenters that address the matter support, or do not oppose, approval of the revised suite of TOP and IRO Reliability Standards. We determine that NERC's approach of consolidating requirements and removing redundancies generally has merit and is consistent with Commission policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[14]

14. We also determine that the proposed TOP and IRO Reliability Standards should improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators.[15] The proposed TOP Reliability Standards will eliminate multiple TOP standards, resulting in a more concise set of standards, reducing redundancy and more clearly delineating responsibilities between applicable entities. In addition, we find that the proposed Reliability Standards provide a comprehensive framework as well as important improvements to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. The TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions.

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[14] *See* Order No. 788, 145 FERC ¶ 61,147.

[15] *See, e.g.*, Order No. 748, 134 FERC ¶ 61,213, at PP 39-40.

15. In the NOPR, the Commission proposed to find that NERC adequately addressed the concerns raised by the Commission in the Remand NOPR with respect to (1) the treatment of SOLs in the proposed TOP Reliability Standards, and (2) the IRO standards regarding planned outage coordination, both of which we address below.

Operational Responsibilities and Actions of SOLs and IROLs

16. In the Remand NOPR, the Commission expressed concern that the initially proposed (now withdrawn) TOP standards did not have a requirement for transmission operators to plan and operate within all SOLs. The Commission finds that the TOP Reliability Standards that NERC subsequently proposed address the Commission's Remand NOPR concerns by requiring transmission operators to plan and operate within all SOLs, and to monitor and assess SOL conditions within and outside a transmission operator's area. Further, the TOP/IRO Standards approved herein address 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 if not addressed. Likewise, the Reliability Standards give reliability coordinators the authority to direct actions to prevent or mitigate instances of exceeding IROLs because the primary decision-making authority for mitigating IROL exceedances is assigned to reliability coordinators while transmission operators have the primary responsibility for mitigating SOL exceedances.[16]

[16] *See* Remand NOPR, 145 FERC ¶ 61,158 at P 85. Further, currently-effective Reliability Standard IRO-009-1, Requirement R4 states that "[w]hen actual system

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17. Furthermore, the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs, IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.[17]

Outage Coordination

18. In the NOPR, the Commission explained that NERC had addressed concerns raised in the Remand NOPR with respect to the IRO standards regarding planned outage coordination. In the Remand NOPR, the Commission expressed concern with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a (subjects of the proposed remand and now withdrawn by NERC) did not require the

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conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_v."

[17] NERC Petition at 17-18.

coordination of outages, noting that outage coordination is a critical reliability function that should be performed by the reliability coordinator.[18]

19. In the NOPR, the Commission noted that Reliability Standard IRO-017-1, Requirement R1 requires each reliability coordinator to develop, implement and maintain an outage coordination process for generation and transmission outages within its reliability coordinator area. Additionally, 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. We believe that these proposed standards adequately address our concerns with respect to outage coordination as outlined in the Remand NOPR. However, as we discuss below we direct NERC to modify the standards to include transmission operator monitoring of non-BES facilities, and to specify that data exchange capabilities include redundancy and diverse routing; as well as testing of the alternate or less frequently used data exchange capability, within 18 months of the effective date of this Final Rule.

20. Below we discuss the following matters: (A) possible inconsistencies of identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of

[18] Remand NOPR, 145 FERC ¶ 61,158 at P 90.

the load-serving entity function from proposed Reliability Standard TOP-001-3; (D) data exchange capabilities, and (E) other issues raised by commenters.

A. <u>Possible Inconsistences in IROLs Across Regions</u>

<u>NOPR</u>

21. In the NOPR, the Commission noted that in Exhibit E (SOL White Paper) of NERC's petition, NERC stated that, with regard to the SOL concept, the SOL White Paper brings "clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."[19] The Commission further noted that IROLs, as defined by NERC, are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system. The Commission agreed with NERC that clarity and consistency are important with respect to establishing and implementing operating plans to mitigate SOL and IROL exceedances. However, the Commission noted that NERC, in its 2015 State of Reliability report, had stated that the Western Interconnection reliability coordinator definition of an IROL has additional criteria that may not exist in other reliability coordinator areas.[20] The Commission stated

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[19] NERC Petition, Exhibit E, "White Paper on System Operating Limit Definition and Exceedance Clarification" at 1.

[20] NOPR, 151 FERC ¶ 61,236 at P 51, citing NERC 2015 State of Reliability report at 44, *available at* www.nerc.com. *See also* WECC Reliability Coordination System Operating Limits Methodology for the Operations Horizon, Rev. 7.0 (effective March 3, 2014) at 18 (stating that "SOLs qualify as IROLs when … studies indicate that instability, Cascading, or uncontrolled separation may occur resulting in uncontrolled

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that it is unclear whether NERC regions apply a consistent approach to identifying IROLs. The Commission, therefore, sought comment on (1) identification of all regional differences or variances in the formulation of IROLs; (2) the potential reliability impacts of such differences or variations, and (3) the value of providing a uniform approach or methodology to defining and identifying IROLs.

Comments

22. Commenters generally agree that there are variations in IROL formulation but maintain that the flexibility is needed due to different system topographies and configurations. EEI and other commenters, also suggest that, to the extent there are variations, such resolution should be addressed by NERC and the Regional Entities in a standard development process rather than by a Commission directive. NERC requests that the Commission refrain from addressing these issues in this proceeding. NERC contends that the TOP and IRO Reliability Standards do not address the methods for the development and identification of SOLs and IROLs and that requirements governing the development and identification of SOLs and IROLs are included in the Facilities Design, Connections and Maintenance (FAC) Reliability Standards. NERC states that the current FAC Reliability Standards provide reliability coordinators flexibility in the manner in

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interruption of load equal to or greater than 1000 MW"), *available at* https://www.wecc.biz/Reliability/PhaseII%20WECC%20RC%20SOL%20Methodology%20FINAL.pdf.

which they identify IROLs.[21] NERC adds that it recently initiated a standards development project (Project 2015-09 Establish and Communicate System Operating Limits) to evaluate and modify the FAC Reliability Standards that address the development and identification of SOLs and IROLs. NERC explains that the Project 2015-09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs. According to NERC, it would be premature for NERC or the Commission to address issues regarding the identification of IROLs in this proceeding without the benefit of the complete analysis of the Project 2015-09 standard drafting team. NERC commits to working with stakeholders and Commission staff during the Project 2015-09 standards development process to address the issues raised in the NOPR.

23. ERCOT comments that the existing Reliability Standards provide a consistent but flexible structure for IROL identification that provides maximum benefit to interconnected transmission network. ERCOT believes that the Reliability Standards should continue to permit regional variations that will encourage flexibility for consideration of system-specific topology and characteristics as well as the application of operational experience and engineering judgment. ERCOT states that regional differences exist in terms of the specific processes and methodologies utilized to identify IROLs. However, according to ERCOT, appropriate consistency in IROL identification

[21] *See also* Peak Comments at 4-5. Peak points to Reliability Standards FAC-011-2 and FAC-014-2 as support for regional variation in establishing IROLs.

is driven by the definition of an IROL, the Reliability Standards associated with the identification of SOLs, and the communication and coordination among responsible entities. Further, ERCOT argues that allowing regional IROL differences benefits the bulk electric system by allowing the entities with the most operating experience to recognize the topology and operating characteristics of their areas, and to incorporate their experience and judgment into IROL identification.

24. Peak supports allowing regions to vary in their interpretation and identification of IROLs based on the level of risk determined by that region, as long as that interpretation is transparent and consistent within that region. Peak understands the definition of IROL to recognize regional differences and variances in the formulation of IROLs. Peak contends that such regional variation is necessary due to certain physical system differences. Thus, according to Peak, a consistent approach from region to region is not required, and may not enhance the overall reliability of the system. Peak explains that, in the Western United States, the evaluation of operating limits and stability must take into account the long transmission lines and greater distance between population centers, a situation quite different than the dense, interwoven systems found in much of the Eastern Interconnection. Peak adds that the Western Interconnection more frequently encounters localized instability because of the sparsity of the transmission system and the numerous small load centers supplied by few transmission lines, and these localized instances of instability have little to no impact on the overall reliability of the bulk electric system. Peak encourages the Commission to recognize that differences among the regions may

require flexibility to determine, through its SOL methodology, the extent and severity of instability and cascading that warrant the establishment of an IROL.

25. While Peak supports retaining the flexibility of a region by region application of the IROL definition, Peak notes that the current definition is not without some confusing ambiguity in the application of IROL that should be addressed, including ambiguity and confusion around the term “instability,” the phrase “that adversely impact the reliability of the Bulk Electric System” and “cascading.” Peak suggests that one method to eliminate confusion on the definition and application of IROLs would be to expand NERC’s whitepaper to address concerns more specific to IROLs. Peak contends that further guidance from NERC in the whitepaper may remedy the confusion on the limits on the application of IROLs for widespread versus localized instability.

26. Peak requests that, if the Commission or NERC determines that a one-size-fits all approach is necessary for the identification of IROLs and eliminates the current flexibility for regional differences, that the Commission recognizes the limitations this will place on reliability coordinators to evaluate the specific conditions within their reliability coordinator area. The Commission should require that any standardized application of the IROL definition would need to address specific thresholds and implementation triggers for IROLs based on the risk profile and challenges facing specific regions, to avoid the downfalls of inaccurate or overbroad application, as discussed above.

Commission Determination

27. While it appears that regional discrepancies exist regarding the manner for calculating IROLs, we accept NERC's explanation that this issue is more appropriately addressed in NERC's Facilities Design, Connections and Maintenance or "FAC" Reliability Standards. NERC indicates that an ongoing FAC-related standards development project - NERC Project 2015-09 (Establish and Communicate System Operating Limits) - will address the development and identification of SOLs and IROLs. We conclude that NERC's explanation, that the Project 2015-09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs, is reasonable. Therefore, we will not direct further action on IROLs in the immediate TOP and IRO standard-related rulemaking. However, when this issue is considered in Project 2015-19, the specific regional difference of WECC's 1,000 MW threshold in IROLs should be evaluated in light of the Commission's directive in Order No. 802 (approving Reliability Standard CIP-014) to eliminate or clarify the "widespread" qualifier on "instability" as well as our statement in the Remand NOPR that "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability."[22]

[22] *Physical Security Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (2014) and Remand NOPR, 145 FERC ¶ 61,158 at P 52. *See also* FPA section 215(a)(4) defining Reliable Operation as "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of

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B. Monitoring of Non-Bulk Electric System Facilities

NOPR

28. In the NOPR the Commission proposed to find that the proposed Reliability Standards adequately address the 2011 Southwest Outage Blackout Report recommendation regarding monitoring sub-100 kV facilities, primarily because of the responsibility of the reliability coordinator under proposed Reliability Standard IRO-002-4, Requirement R3 to monitor non-bulk electric system facilities to the extent necessary. The Commission noted, however, that "the transmission operator may have a more granular perspective than the reliability coordinator of its necessary non-bulk electric system facilities to monitor," and it is not clear whether or how the transmission operator would provide information to the reliability coordinator regarding which non-BES facilities should be monitored.[23] The Commission sought comment on how NERC will ensure that the reliability coordinator will receive such information.

29. The Commission stated that including such non-bulk electric system facilities in the definition of bulk electric system through the NERC Rules of Procedure exception process could be an option to address any potential gaps for monitoring facilities but notes that there may be potential efficiencies gained by using a more expedited method to include non-bulk electric system facilities that requires monitoring. The Commission

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a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

[23] NOPR, 151 FERC ¶ 61,236 at P 58.

sought comment on whether the BES exception process should be used exclusively in all cases. Alternatively, the Commission sought comment on whether this concern can be addressed through a review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring.

Comments

30. Nearly all commenters support the Reliability Standards as proposed as sufficient for identifying and monitoring non-bulk electric system facilities, and do not support the alternatives offered by the Commission in the NOPR.[24] NERC submits that the proposed data specification and collection Reliability Standards IRO-010-2 and TOP-003-3, in addition to the exceptions process will help ensure that the reliability coordinator can work with transmission operators, and other functional entities, to obtain sufficient information to identify the necessary non-bulk electric system facilities to monitor. In support, NERC points to Reliability Standard IRO-010-2, which 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. Further, NERC cites Reliability Standard TOP-003-3, which allows transmission operators to obtain data on non-bulk electric system facilities, necessary to perform their operational planning analyses, real-time monitoring, and real-time assessments from applicable entities. NERC explains that any data that the transmission operator obtains

[24] *E.g.* NERC, EEI, TAPS, Occidental, and NIPSCO.

regarding non-bulk electric system facilities under Reliability Standard TOP-003-3 can be passed on to the reliability coordinator pursuant to a request under proposed Reliability Standard IRO-010-2. Accordingly, NERC states that it would be premature to develop an alternative process before the data specification and bulk electric system exception process are allowed to work.

31. EEI states that this issue has been thoroughly studied by NERC through Project 2010-17 Phase 2 (Revisions to the Definition of Bulk Electric System) that led to modification of the definition of bulk electric system. EEI believes that the current process provides all of the necessary tools and processes to ensure that insights by TOPs are fully captured and integrated into existing monitoring systems that would ensure that all non-BES elements that might impact BES reliability are fully monitored. EEI does not support the alternative process proposed by the Commission. EEI warns that an alternative, parallel review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring would either circumvent the revised bulk electric system definition process or arbitrarily impose NERC requirements (i.e., monitoring) onto non-bulk electric system elements.

32. APS agrees with the Commission that there would be a reliability benefit for the reliability coordinator to be able to identify facilities within the transmission operators' areas that may have a material impact on reliability. APS believes this benefit can be achieved using the method deployed in the Western Interconnection by the Western Electricity Coordinating Council (WECC). APS explains that the WECC planning coordination committee has published a bulk electric system inclusion guideline that

categorizes non-bulk electric system facilities that are to be identified by each planning authority and transmission planner when performing their system planning and operations reliability assessments, and the identified facilities are then reported to NERC. APS proposes a similar exception process be used in all cases. According to APS, each reliability coordinator would publish a guideline on how to identify non-bulk electric system facilities critical to reliability appropriate for their reliability coordinator area, and each planning coordinator and transmission planner would run studies according to the reliability coordinator guideline at least once every three years.

33. ERCOT states that performance of sufficient studies and evaluations of reliability coordinator areas occurs in cooperation and coordination with associated transmission operators, rending an additional review process unnecessary. However, to avoid any potential gaps in monitoring non-bulk electric system facilities and ensure that existing agreements and monitoring processes are respected, ERCOT states that the Commission should direct NERC to modify the TOP and IRO Reliability Standards to refer not only to sub-100 kV facilities identified as part of the bulk electric system through the Rules of Procedure exception process, but also to other sub-100 kV facilities as requested or agreed by the responsible entities.[25] ERCOT also states that because “non-bulk electric system facilities” fall outside the scope of the NERC Reliability Standards, use of this terminology should be avoided. ERCOT advocates for the Commission to permit

[25] *See also* ISO/RTOs Comments at 3.

monitoring of other sub-100 kV facilities to be undertaken as agreed to between the reliability coordinator and the transmission operator. ERCOT and ISO/RTOs suggest that the phrase "non-BES facilities" in Reliability Standard IRO-002-4, Requirement R3 should be replaced with "sub-100 kV facilities identified as part of the BES through the BES exception process or as otherwise agreed to between the Reliability Coordinator and Transmission Operator" and the phrase "non-BES data" in Reliability Standards IRO-010-2 (Requirement R1.1) and TOP-003-3 (Requirement R1.1) should be replaced with "data from sub-100 kV facilities identified as part of the BES through the BES exception process, as otherwise requested by the Responsible Entity, or as agreed to between the Transmission Operator and the Responsible Entity."[26]

34. ITC does not support the Commission's proposal. ITC states that transmission operators are required to incorporate any non-bulk electric system data into operational planning analysis and real-time assessments and monitoring, which therefore requires transmission operators to regularly review their models to identify impacting non-bulk electric system facilities. Conversely, ITC explains that conducting a one-time or periodic review and analysis of a transmission operator's model ignores the fact that changes in system conditions can cause the list of impacting non-bulk electric system facilities to change frequently.

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[26] *See also* ISO/RTOs Comments at 4-6.

Commission Determination

35. We agree with NERC, TAPS, and EEI that the BES exception process can be a mechanism for identifying non-BES facilities to be included in the BES definition.[27] Indeed, *once* a non-BES facility is included in the BES definition under the BES exception process, the "non-BES facility" becomes a BES "Facility" under TOP-001-3, Requirement R10, and real-time monitoring is required of "Facilities."[28] However, we are concerned that in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap. As the 2011 Southwest Outage Report indicates, the Regional Entity "should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and *actively monitored* and alarmed in

[27] NERC TOP/IRO Petition, Exh. G at 9 states in response to the 2011 Southwest Outage Recommendation #17, "If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in proposed TOP-001-3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities.'"

[28] NERC Glossary of Terms defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"

[real-time contingency analysis] systems."[29] Such monitoring of non-BES facilities could provide a "stop gap" during the period where a sub-100 kV facility undergoes analysis as a possible BES facility, allowing for monitoring in the interim until such time the non-bulk electric system facilities become "BES Facilities" or the transmission operator determines that a non-bulk electric system facility is no longer needed for monitoring to determine a system operating limit exceedance in its area.[30] We believe that the operational planning analyses and real-time assessments performed by the transmission operators as well as the reliability coordinators will serve as the basis for determining which "non-BES facilities" require monitoring to determine system operating limit and interconnection reliability operating limit exceedances. In addition, we believe that monitoring of certain non-BES facilities that are occasional system operating limit exceedance performers may not qualify as a candidate for inclusion in the

[29] NOPR, 151 FERC ¶ 61,236 at P 55, citing Recommendation 17 of the 2011 Southwest Outage Blackout Report (emphasis added).

[30] NERC's BES Frequently Asked Questions, Version 1.6, February 25, 2015, Section 5.6. "How long will the process take?" at page 14 states: "In general, assuming a complete application, no appeals, and taking the allotted time for each subtask, the process could take up to 11.5 months, but is anticipated to be shorter for less complicated Exception Requests. If the Exception Request is appealed to the NERC Board of Trustees Compliance Committee pursuant to Section 1703 of the NERC Rules of Procedure, the process could take an additional 8.5 months, totaling 20 months. This does not include timing related to an appeal to the applicable legal authority or Applicable Governmental Authority. A Regional Entity, upon consultation with NERC, may extend the time frame of the substantive review process…." http://www.nerc.com/pa/RAPA/BES%20DL/BES%20FAQs.pdf.

BES definition, yet should be monitored for reliability purposes.[31] Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary. NERC can develop an equally efficient and effective alternative that addresses our concerns.[32]

36. To be clear, we are not directing that all current "non-BES" facilities that a transmission operator considers worthy of monitoring also be included in the bulk electric system. We believe that such monitoring may result in some facilities becoming part of the bulk electric system through the exception process; however it is conceivable that others may remain non-BES because they are occasional system operating limit exceedance performers that may not qualify as a candidate for inclusion in the BES definition.

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[31] *See, e.g.*, NERC TOP/IRO Petition at 18 and 27-28.

[32] Reliability Standard IRO-002-4, Requirement R3 states: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

C. Removal of Load-Serving Entity Function from TOP-001-3 NOPR

37. NERC proposed the removal of the load-serving entity function from proposed Reliability Standard, TOP-001-3, Requirements R3 through R6, as a recipient of an operating instruction from a transmission operator or balancing authority. NERC supplemented its initial petition with additional explanation for the removal of the load-serving entity function from proposed Reliability Standard TOP-001-3.[33] NERC explained that the proposed standard gives transmission operators and balancing authorities the authority to direct the actions of certain other functional entities by issuing an operating instruction to maintain reliability during real-time operations.

38. In the NOPR, the Commission noted that NERC was required to make a compliance filing in Docket No. RR15-4-000, regarding NERC's Risk-Based Registration initiative, and that the Commission's decision on that filing will guide any action in this proceeding. On March 19, 2015, the Commission approved, in part, NERC's Risk-Based Registration initiative, but denied, without prejudice, NERC's proposal to eliminate the load-serving entity function from the registry process, finding that NERC had not adequately justified its proposal.[34] In doing so, the Commission

[33] The Commission also notes that Reliability Standards TOP-003-3 and IRO-010-2 also include "load-serving entity" as an applicable entity.

[34] *North American Electric Reliability Corp.* 150 FERC ¶ 61,213 (2015) (March 19 Order).

directed NERC to provide additional information to support this aspect of its proposal to address the Commission's concerns. On July 17, 2015, NERC submitted a compliance filing in response to the March 19 Order.

Comments

39. NERC states that while load-serving entities play a role in facilitating interruptible (or voluntary) load curtailments, that role is to simply communicate requests for voluntary load curtailments and does not necessitate requiring load-serving entities to comply with a transmission operator's or balancing authority's operating instructions issued pursuant to Reliability Standard TOP-001-3. In short, the load-serving entity's role in carrying out interruptible load curtailment is not the type of activity that rises to the level of requiring an operating instruction. EEI and TAPS contend it is appropriate to omit the load-serving entity function from TOP-001-3 applicability. TAPS explains that because the load-serving entity function does not own or operate equipment, the load-serving entity function cannot curtail load or perform other corrective actions subject to reliability standards. Dominion asserts that a load-serving entity does not own or operate bulk electric system facilities or equipment or the facilities or equipment used to serve end-use customers and is not aware of any entity, registered solely as a load-serving entity, which is responsible for operating one or more elements or facilities.

Commission Determination

40. In an October 15, 2015 order in Docket No. RR15-4-001, the Commission accepted a NERC compliance filing, finding that NERC complied with the March 17 Order with respect to providing additional information justifying the removal of the load-

serving entity function.[35] The Commission also found that NERC addressed the concerns expressed regarding an accurate estimate of the load-serving entities to be deregistered and the reliability impact of doing so, and how load data will continue to be available and reliability activities will continue to be performed even after load-serving entities would no longer be registered.[36] Because the load-serving entity category is no longer a NERC registration function, no further action is required in this proceeding.[37]

D. <u>Data Exchange Capabilities</u>

41. The Commission approved Reliability Standards COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols) in Order No. 808, and noted that in the NOPR underlying that order (COM NOPR) it had raised concerns as to whether Reliability Standard COM-001-2 addresses facilities that directly exchange or transfer data.[38] In response to that concern in the COM NOPR, NERC clarified that Reliability Standard COM-001-2 did not need to include requirements regarding data exchange capability because such capability is covered under other existing and proposed

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[35] *North American Electric Reliability Corp*, 153 FERC ¶ 61,024 (2015).

[36] *Id.*

[37] In its response to comments in Docket No. RR15-4-000, NERC stated that, once the Commission approved the proposed deactivation of the load-serving entity registration function, it would make any needed changes to the Reliability Standards through the Reliability Standard Development Process. *See* January 26, 2016, NERC Motion to File Limited Answer at 6 in Docket No. RR15-4-000.

[38] *See* NOPR, 151 FERC ¶ 61,236 at P 67, citing *Communications Reliability Standards*, Order No. 808, 151 FERC ¶ 61,039 (2015).

standards. Based on that explanation, the Commission decided not to make any determinations in Order No. 808 and stated that it would address the issue in this TOP and IRO rulemaking proceeding.[39]

NOPR

42. In the NOPR, the Commission stated that facilities for data exchange capabilities appear to be addressed in NERC's TOP/IRO petition. However, the Commission sought additional explanation from NERC regarding how it addresses data exchange capabilities in the TOP and IRO Standards in the following areas: (a) redundancy and diverse routing; and (b) testing of the alternate or less frequently used data exchange capability.

1. Redundancy and Diverse Routing of Data Exchange Capabilities

NOPR

43. In the NOPR, the Commission agreed that proposed Reliability Standard TOP-001-3, Requirements R19 and R20 require some form of "data exchange capabilities" for the transmission operator and balancing authority and that proposed Reliability Standard TOP-003-3 addresses the operational data itself needed by the transmission operator and balancing authority. In addition, the Commission agreed that Reliability Standard IRO-002-4, Requirement R1 requires "data exchange capabilities" for the reliability coordinator and that proposed Reliability Standard IRO-010-2 addresses the operational data needed by the reliability coordinator and that proposed Reliability Standard IRO-

[39] *Id.* citing Order No. 808, 151 FERC ¶ 61,039 at P 54.

002-4 Requirement R4 requires a redundant infrastructure for system monitoring. However, the Commission was concerned that it is not clear whether redundancy and diverse routing of data exchange capabilities were adequately addressed in proposed Reliability Standards TOP-001-3 and IRO-002-4 for the reliability coordinator, transmission operator, and balancing authority and sought explanation or clarification on how the standards address redundancy and diverse routing or an equally effective alternative. The Commission also stated that, if NERC or others believe that redundancy and diverse routing are not addressed, they should address whether there are associated reliability risks of the interconnected transmission network for any failure of data exchange capabilities that are not redundant and diversely routed.

Comments

44. NERC and EEI state that the requirements in the TOP and IRO Reliability Standards covering data exchange are results-based, articulating a performance objective without dictating the manner in which it is met. NERC adds that, in connection with their compliance monitoring activities, NERC and the Regional Entities will review whether applicable entities have met that objective, and will consider whether the applicable entity has redundancy and diverse routing, and whether the applicable entity tests these capabilities. EEI also argues that Reliability Standard EOP-008-1, Requirements R1, R1.2, R1.2.2, R7, and EOP-001-2.1b, Requirements R6 and R6.1 provide specific requirements for maintaining or specifying reliable back-up data exchange capability necessary to ensure BES Reliability and the testing of those capabilities.

45. ERCOT asserts that the Reliability Standards already appropriately provide for redundancy and diversity of routing of data exchange capabilities, as both the existing and proposed standards either explicitly or implicitly require responsible entities to ensure availability of data and data exchange capabilities. ERCOT states that, should the Commission seek to provide further clarification on this issue, such clarification should be consistent with existing explicit requirements regarding the redundancy of data exchange capabilities, such as Requirement R4 of Reliability Standard IRO-002-4.

46. ISOs/RTOs and ERCOT explain the suite of currently-effective standards and the proposed TOP and IRO standards establish performance-based requirements for reliability coordinators, balancing authorities, and transmission operators, that create the need for those entities to have diverse and redundantly routed data communication systems. In the event of a failure of data communications, ISOs/RTOs explain that the functional entity should be able to rely on the redundant and diversely routed <u>voice capabilities</u> required in the COM standards.

<u>Commission Determination</u>

47. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations. NERC's comprehensive approach to establishing

communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here.[40] Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, we direct NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.

48. Further, we disagree with commenter arguments that Reliability Standard EOP-008-1 provides alternatives to data exchange redundancy and diverse routing. The NERC standard drafting team that developed the COM standards addressed this issue in the standards development process, responding to a commenter seeking clarification on the relationship between communication capabilities, alternative communication capabilities, primary control center functionality and backup control center functionality. The standard drafting team responded that "Interpersonal Communication and Alternative Interpersonal Communication <u>are not related to EOP-008</u>," even though Reliability

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[40] *See, e.g,* Order No. 808, 151 FERC ¶ 61,039 at P 8: "NERC stated in its [COM] petition that Reliability Standard COM-001-2 establishes requirements for Interpersonal Communication capabilities necessary to maintain reliability. NERC explained that proposed Reliability Standard COM-001-2 applies to reliability coordinators, balancing authorities, transmission operators, generator operators, and distribution providers. The proposed Reliability Standard includes eleven requirements and two new defined terms, "Interpersonal Communication" and "Alternative Interpersonal Communication," that, according to NERC, collectively provide a comprehensive approach to establishing communications capabilities necessary to maintain reliability."

Standard EOP-008-1 Requirement R1 applies equally to data communications and voice communications.[41] To the extent the standard drafting team asserted that Reliability Standard EOP-008 did not supplant the redundancy requirements of the COM Reliability Standards, we believe the same is true for data communications. Redundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communications.

2. Testing of the Alternate or Less Frequently Used Data Exchange Capability

NOPR

49. In the NOPR, the Commission expressed concern that the proposed TOP and IRO Reliability Standards do not appear to address testing requirements for alternative or less frequently used mediums for data exchange to ensure they would properly function in the event that the primary or more frequently used data exchange capabilities failed. Accordingly, the Commission sought comment on whether and how the TOP and IRO Reliability Standards address the testing of alternative or less frequently used data exchange capabilities for the transmission operator, balancing authority and reliability coordinator.

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[41] *See* NERC COM Petition, Exh. M, (Consideration of Comments on Initial Ballot, February 25 - March 7, 2011) at 30 (emphasis added).

Comments

50. Commenters assert that the existing standards have sufficient testing requirements. NERC points to Reliability Standard EOP-008-1, Requirement R7, which requires that applicable entities conduct annual tests of their operating plan that demonstrates, among other things, backup functionality. Similarly, EEI cites EOP-008-1 Requirements R1, R1.2, R1.2.2, R7 and EOP-001-2.1b Requirements R6 and R6.1 as providing specific requirements for maintaining and testing of data exchange capabilities. ITC suggests that NERC's proposed Standard TOP-001-3 provides ample assurance that the data exchange capabilities are regularly tested and also points to Reliability Standards EOP-001-2.1b and EOP-008-1 which require entities, including those covered by TOP-001-3, to maintain reliable back-up data exchange capability as necessary to ensure reliable BES operations, and require that such capabilities be thoroughly and regularly tested.

Commission Determination

51. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to test alternate data exchange capabilities. However, we are not persuaded by the commenters' assertions that the need to test is implied in the TOP and IRO Standards. Rather, we determine that testing of alternative data exchange capabilities is important to reliability and should not be left to what may or may not be implied in the standards.[42] Therefore, pursuant to

[42] In NERC's COM Petition, Exh. M, (Consideration of Comments, Index to Questions, Comments and Responses) at 35, the standard drafting team stated that the

(continued ...)

section 215(d)(5) of the FPA, we direct NERC to develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority. We believe that the structure of Reliability Standard COM-001-2, Requirement R9 could be a model for use in the TOP and IRO Standards.[43]

E. Other Issues Raised by Commenters

1. Emergencies and Emergency Assistance Under Reliability Standard TOP-001-3

52. Reliability Standard TOP-001-3, Requirement R7 requires each transmission operator to 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. NIPSCO contends that this requirement limits the ability of an adjacent transmission operator that is located along the seam in another reliability coordinator area from rendering assistance in an emergency because Requirement R7 only requires each transmission operator to assist other transmission

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"requirement [COM-001-2, Requirement R9 which addresses testing of alternative interpersonal communication] applies to the primary control center" and "EOP-008 applies to the back up control center."

[43] COM-001-2, Requirement R9 states: "Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours."

operators within its reliability coordinator area. NIPSCO points to Reliability Standard IRO-014-3, Requirement R7 which requires each reliability coordinator to assist other reliability coordinators and, according to NIPSCO, a similar requirement in Reliability Standard TOP-001-3 will make the two sets of requirements consistent with each other.

53. In addition, Reliability Standard TOP-001-3, Requirement R8 states:

> Each Transmission Operator shall 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.

BPA contends that the phrase "could result in" in Requirement R8 of TOP-001-3 is overly broad and suggests corrective language underscored below:

> Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in an Emergency, or could result in an Emergency <u>if a credible Contingency were to occur</u>.

As an alternative to changing the language of the requirement, BPA asks the Commission to clarify that it is in the transmission operator's discretion to determine what "could result" in an emergency, based on the transmission operator's experience and judgment.

<u>Commission Determination</u>

54. With regard to NIPSCO's concern, we do not believe that the requirements as written limit the ability of an adjacent transmission operator located along the seam in another reliability coordinator area from rendering assistance in an emergency. We agree with NIPSCO that proposed Reliability Standard TOP-001-3, Requirement R7 requires

each transmission operator to assist other transmission operators within its reliability coordinator area and further agree with NIPSCO that proposed Reliability Standard IRO-014-3, Requirement R7 requires each reliability coordinator to assist other reliability coordinators.[44] In addition, we understand that an adjacent transmission operator in another reliability coordinator area can render assistance when directed to do so by its own reliability coordinator.[45] Having a similar requirement in Reliability Standard TOP-001-3 compared to Reliability Standard IRO-014-3, Requirement R7 is unnecessary and could complicate the clear decision-making authority NERC developed in the TOP and IRO Reliability Standards. Thus, we determine that no further action is required.

55. With regard to clarification of emergencies in Reliability Standard TOP-001-3, Requirement R8, we do not see a need to modify the language as suggested by BPA. The requirement as written implies that the transmission operator has discretion to determine what could result in an emergency, based on its experience and judgment. In addition, we note that the transmission operators' required next-day operational planning analysis, real-time assessments and real-time monitoring under the TOP Reliability Standards provide evaluation, assessment and input in determining what "could result" in an emergency.

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[44] *See* Reliability Standards TOP-001-3 and IRO-014-3.

[45] *See* Reliability Standard IRO-001-4, Requirement R2.

2. Reliability Coordinator Authority in Next-Day Operating Plans

56. Reliability Standard TOP-002-4, Requirements R2 and R4 require transmission operators and balancing authorities to have operating plans. Reliability Standard TOP-002-4, Requirements R6 and R7 require transmission operators and balancing authorities to provide their operating plans to their reliability coordinators and Reliability Standard IRO-008-2, Requirement R2 requires reliability coordinators to develop a coordinated operating plan that considers the operating plans provided by the transmission operators and balancing authorities.

57. NIPSCO is concerned about the absence of any required direct coordination between transmission operators and balancing authorities as well as the absence of any guidance regarding the resolution of potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO contends that the Reliability Standards provide only a limited coordination process in which reliability coordinators are required to notify those entities identified with its coordinated operating plan of their roles. NIPSCO argues that there is no provision for modifications to operating plans based on the reliability coordinator's coordinated operating plan or based on potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO is concerned that a potential disconnect between operating plans could lead to confusion or a failure of coordination of reliable operations.

Commission Determination

58. We believe that proposed Reliability Standards TOP-002-4 and IRO-008-2 along with NERC's definition of reliability coordinator address NIPSCO's concern.[46] Although the transmission operator and balancing authority develop their own operating plans for next-day operations, both the transmission operator and balancing authority notify entities identified in the operating plans as to their role in those plans. Further, each transmission operator and balancing authority must provide its operating plan for next-day operations to its reliability coordinator.[47] In Reliability Standard IRO-008-2, Requirement R2, the reliability coordinator must have a coordinated operating plan for next-day operations to address potential SOL and IROL exceedances while considering the operating plans for the next-day provided by its transmission operators and balancing authorities. Also, Reliability Standard IRO-008-2, Requirement R3 requires that the reliability coordinator notify impacted entities identified in its operating plan as to their role in such plan. Based on the notification and coordination processes of Reliability Standards TOP-002-4 (for the transmission operator and balancing authority) and IRO-

[46] NERC Glossary of Terms defines the Reliability Coordinator as "The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision."

[47] Reliability Standard TOP-002-4 (Operations Planning).

008-2 (for the reliability coordinator) for next-day operating plans, as well as the fact that the reliability coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, we believe that the reliability coordinator has the authority and necessary next-day operational information to resolve any next-day operational issues within its reliability coordinator area. Accordingly, we deny NIPSCO's request.

3. <u>Reliability Coordinator Authority in Next-Day Operations and the Issuance of Operating Instructions</u>

59. NIPSCO is concerned with the elimination of the explicit requirement in currently-effective Reliability Standard IRO-004-2 that each transmission operator, balancing authority, and transmission provider comply with the directives of a reliability coordinator based on next-day assessment in the same manner as would be required in real-time operating conditions. NIPSCO claims that, while the Reliability Standards appear to address the Commission's concerns regarding directives issued in other than emergency conditions through the integration of the term "operating instruction," the standards only allow for the issuance of directives in real-time. NIPSCO points to Reliability Standard TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, where transmission operators, balancing authorities, and reliability coordinators are explicitly given authority and responsibility to issue operating instructions to address reliability in their respective areas. NIPSCO states that "operating instruction" is "clearly limited to real-time operations" as it underscored below:

> A command by operating personnel responsible for the <u>Real-time operation</u> of the interconnected Bulk Electric System <u>to change or</u>

> 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.)

NIPSCO contends that there are no clear requirements addressing potential conflicts between operating plans, no clear requirements authorizing the issuance of a directive to address issues identified in next-day planning, and no clear requirement to comply with any directive so issued. NIPSCO is concerned that this raises the possibility that potential next-day problems identified in the operational planning analyses may not get resolved in the next-day planning period because the reliability coordinator's authority to issue operating instructions is limited to real-time operation. According to NIPSCO, this limitation undermines some of the usefulness of the next-day planning and the performance of operational planning analyses.

Commission Determination

60. We do not share NIPSCO's concern. Rather, we believe that, because the reliability coordinator is required to have a coordinated operating plan for the next-day operations, the reliability coordinator will perform its task of developing a coordinated operating plan in good faith, with inputs not only from its transmission operators and balancing authorities, but also from its neighboring reliability coordinators.[48] A reliability coordinator has a wide-area view and bears the ultimate responsibility to

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[48] *See* Reliability Standards IRO-008-2, Requirements R1 and R2, and IRO-014-3, Requirement R1.

maintain the reliability within its footprint, "including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations."[49]

61. In addition, we do not agree with NIPSCO's claim that operating instructions are "clearly limited to real-time operations." The phrase "real-time operation" in the definition of operating instruction as emphasized by NIPSCO applies to the entity that issues the operating instruction which is "operating personnel responsible for the Real-time operation." The definition of operating instruction is "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System…." In addition, the time horizons associated with the issuance of or compliance with an operating instruction are not found in the definition of operating instructions, but found in the individual requirement(s) applicable to issuing an operating instruction. For example, Reliability Standard TOP-001-3, Requirements R1 through R6 and IRO-001-4, Requirements R1 through R3 are all requirements associated with the issuance or compliance of operating instructions. In all nine requirements, the defined time horizon is "same-day operations" and "real-time operations."[50] Accordingly, we deny NIPSCO's request on this issue.

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[49] *See supra* n. 46.

[50] NERC's "Time Horizons" document defines "Same-Day Operations" time horizon as "routine actions required within the timeframe of a day, but not real-time" and defines "Real-Time Operations" time horizon as "actions required within one hour or less to preserve the reliability of the bulk electric system." *See* http://www.nerc.com/files/Time_Horizons.pdf.

4. Updating Operational Planning Analyses and Real-Time Assessments

62. NIPSCO is concerned that the proposed Reliability Standards are not clear as to whether updates or additional analyses are required. NIPSCO points to Reliability Standards IRO-008-2 and TOP-002-4, which require reliability coordinators to perform - and transmission operators and balancing authorities to have - an operational analysis for the next-day, but do not specify when such analysis must be performed or if it needs to be updated in next-day planning based on any change in inputs. Similarly, NIPSCO asserts that the proposed Reliability Standards require the performance of a real-time assessment every 30 minutes but do not address the need to potentially update operating plans based on changes in system conditions (including unplanned outages of protection system degradation) and do not require the performance of additional real-time assessments or other studies with more frequency based on changes in system conditions. NIPSCO explains that it is not clear if or when, based on the operational planning analysis results, some type of additional study or analysis would need to be undertaken prior to the development of an operating plan. According to NIPSCO, the text of the requirements and the definition do not specifically require additional studies; however, it seems that when issues associated with protection system degradation or outages are identified, further study of these issues would be required and/or additional analyses required to update results as protection system status or transmission or generation outages change.

Commission Determination

63. We do not share NIPSCO's concern. Reliability Standards IRO-008-2 and TOP-002-4 require reliability coordinators to perform and transmission operators to have an operational planning analysis to assess whether its planned operations for next-day will exceed any of its SOLs (for the transmission operator) and SOLs/IROLs (for the reliability coordinator). Both are required to have an operating plan(s) to address potential SOL and/or IROL exceedances based on its operational planning analysis results. We believe that, if the applicable inputs of the operational planning analysis change from one operating day to the next operating day, and because an operational planning analysis is an "evaluation of projected system conditions," a new operational planning analysis must be performed to include the change in applicable inputs. Based on the results of the new operational planning analysis for next-day, operating plans may need updating to reflect the results of the new operational planning analysis. Likewise with the real-time assessment, as system conditions change and the applicable inputs to the real-time assessment change, a new assessment would be needed to accurately reflect applicable inputs, as stated in the real-time assessment definition.[51]

[51] Real-time assessment is defined as "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.)."

5. Performing a Real-time Assessment When Real-Time Contingency Analysis Is Unavailable

64. Reliability Standard TOP-001-3, Requirement R13 requires transmission operators to ensure a real-time assessment is performed at least every 30 minutes. NIPSCO states that NERC's definition of real-time assessment anticipates that real-time assessments must be performed through the use of either an internal tool or third-party service.[52] NIPSCO believes that compliance with the requirement to perform a real-time assessment should not be dependent on the availability of a system or tool. According to NIPSCO, if a transmission operators' tools are unavailable for 30 minutes or more, they should be permitted to meet the requirement to assess existing conditions through other means.

Commission Determination

65. Reliability Standard TOP-001-3, Requirement R13 requires the transmission operator to ensure the assessment is performed at least once every 30 minutes, but does not state that the transmission operator on its own must perform the assessment and does not specify a system or tool. This gives the transmission operator flexibility to perform its real-time assessment. Further supporting this flexibility, NERC's definition of real-time assessment states that a real-time assessment "may be provided through internal systems or through third-party services."[53] Therefore, we believe that Reliability

[52] *See supra* n. 48.

[53] NERC TOP/IRO Petition at 18.

Standard TOP-001-3, Requirement R13 does not specify the system or tool a transmission operator must use to perform a real-time assessment. In addition, NERC explains that Reliability Standard TOP-001-3, Requirement R13 and the definition of real-time assessment "do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa."[54] Accordingly, we conclude that TOP-001-3 adequately addresses NIPSCO's concern, namely, if a transmission operators' tools are unavailable for 30 minutes or more, the transmission operator has the flexibility to meet the requirement to assess system conditions through other means.

6. <u>Valid Operating Limits</u>

66. IESO is concerned that the revised TOP standards do not compel an entity to verify existing limits or re-establish limits following an event that results in conditions not previously assessed within an acceptable time frame as is specified in the currently-

[54] NERC TOP/IRO Petition, Exh. K (Summary of Development History and Complete Record of Development), Consideration of Comments May 19, 2014 through July 2, 2014) at 61.

effective Reliability Standard TOP-004-2 Requirement R4.[55] IESO disagrees that this is sufficient because there is no requirement in the Reliability Standard TOP-001-3 standard to derive a new set of limits, particularly transient stability limits, or verify that an existing set of limits continue to be valid for the prevailing conditions within an established timeframe. IESO contends that a real-time assessment is useful only if the system conditions are assessed against a valid set of limits and is unable to verify or re-establish stability-restricted SOLs with which to assess system conditions to address reliability concerns. IESO believes that an explicit requirement to verify or re-establish SOLs when entering into an unstudied state must therefore be imposed to fill this reliability gap.

67. Further, IESO asserts that implementing operating plans to mitigate an SOL exceedance does not require transmission operators to determine a valid set of limits with which to compare the prevailing system conditions (i.e. whether or not the limits are exceeded). While the IESO supports performing a real-time assessment every 30 minutes, it asserts that performing an assessment without first validating the current set of limits or re-establishing a new set of limits as the boundary conditions leaves a reliability gap.

[55] Requirement R4 states: "If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes."

Commission Determination

68. We agree with IESO that valid operating limits, including transient stability limits, are essential to the reliable operation of the interconnected transmission network and that a transmission operator must not enter into an unknown operating state. Further, we agree with IESO that Reliability Standard TOP-001-3 has no requirements to derive a new set of limits or verify an existing set of limits for prevailing operating conditions within an established timeframe. However, IESO's concerns regarding the establishment of transient stability operating limits are addressed collectively through proposed Reliability Standard TOP-001-3, certain currently-effective Facilities Design, Connections, and Maintenance (FAC) Reliability Standards and NERC's Glossary of Terms definition of SOLs.

69. In its SOL White Paper, NERC stated that the intent of the SOL concept is to bring clarity and consistency for establishing SOLs, exceeding SOLs, and implementing operating plans to mitigate SOL exceedances.[56] In addition, "transient stability ratings"

[56] NERC Petition, Exh. E (White Paper on System Operating Limit Definition and Exceedance Clarification) at 1. NIPSCO requests clarification as to how NERC's SOL White Paper can be used in determining compliance. NIPSCO requests that any substantive content that is treated as containing enforceable compliance requirements be filed with the Commission for approval. NERC developed the SOL White Paper as a guidance document which provides links between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective operating plans to mitigate SOL exceedances. Guidelines are illustrative but not mandatory and enforceable compliance requirements. *See, e.g. North American Electric Reliability Corp.*, 143 FERC ¶ 61,271, at P 15 (2013). Accordingly, we see no need for further revisions to the Reliability Standards to incorporate the SOL White Paper as requested by NIPSCO.

are included in the SOL definition. Further, in the SOL White Paper, NERC states that the "concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2 and FAC-014-2."[57] Specific to IESO's concerns of establishing transient stability limits, we agree with NERC that approved Reliability Standard FAC-011-2, Requirement R2 requires that the reliability coordinator's SOL methodology include a requirement that SOLs provide a certain level of bulk electric system performance including among other things, that the "BES shall demonstrate transient, dynamic and voltage stability" and that "all Facilities shall be within their…stability limits" for both pre- and post-contingency conditions.[58] In addition, we note that currently-effective Reliability Standard FAC-011-2, Requirement R2.1 states that "[i]n the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall *reflect changes to system topology* such as Facility outages."[59]

70. With respect to Reliability Standard TOP-001-3, we agree with NERC that Requirement R13 specifies that transmission operators must perform a real-time assessment at least once every 30 minutes, which by definition is an evaluation of system conditions to assess existing and potential operating conditions. The real-time

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[57] NERC Petition, Exh. E at 1.

[58] *Id*. at 2. *See also* Reliability Standard FAC-011-2, Requirement R2.

[59] Reliability Standard FAC-011-1, Requirement R2.1 (emphasis added).

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. In addition, 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.[60] Accordingly, we conclude that the establishment of transient stability operating limits is adequately addressed collectively through proposed Reliability Standard TOP-001-3, currently-effective Reliability Standards FAC-011-2 and FAC-014-2 and NERC's Glossary of Terms definition of SOLs.[61]

III. Information Collection Statement

71. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[62] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[63] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be

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[60] NERC Petition at 57-58.

[61] *See* Reliability Standard FAC-014-2, Requirement R2.

[62] 44 U.S.C. 3507(d) (2012).

[63] 5 C.F.R. § 1320.11.

penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

Public Reporting Burden: The number of respondents below is based on an estimate of the NERC compliance registry for the balancing authority, transmission operator, generator operator, distribution provider, generator owner, load-serving entity, purchasing-selling entity, transmission service provider, interchange authority, transmission owner, reliability coordinator, planning coordinator, and transmission planner functions. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 15, 2015. According to the registry, there are 11 reliability coordinators, 99 balancing authorities, 450 distribution providers, 839 generator operators, 80 purchasing-selling entities, 446 load-serving entities, 886 generator owners, 320 transmission owners, 24 interchange authorities, 75 transmission service providers, 68 planning coordinators, 175 transmission planners and 171 transmission operators. The estimates are based on the change in burden from the current standards to the standards approved in this Final Rule. The following table illustrates the burden to be applied to the information collection:

RM15-16-000 (Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards)						
	Number of Respondents[64] **(1)**	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response**[65] **(4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
FERC-725A						
TOP-001-3	196 (TOP & BA)	1	196	96 hrs. $6,369	18,816 hrs., $1,248,441	96 hrs, $6,369
TOP-002-4	196 (TOP & BA)	1	196	284 hrs. $18,843	55,664 hrs., $3,693,306	284 hrs., $18,843
TOP-003-3	196 (TOP & BA)	1	196	230 hrs. $15,260	45,080 hrs., $2,991,058	230 hrs., $15,260
Sub-Total for FERC-725A					123,252 hrs., $7,932,806	
FERC-725Z						
IRO-001-4[66]	177 (RC & TOP)	1	177	0 hrs. $0	0 hrs. $0	0 hrs. $0
IRO-002-4	11 (RC)	1	11	24 hrs. $1,592	264 hrs., $17,516	24 hrs., $1,592
IRO-008-2	11 (RC)	1	11	228 hrs. $15,127	2,508 hrs., $166,405	228 hrs., $15,127
IRO-010-2	11 (RC)	1	11	36 hrs. $2,388	396 hrs., $26,274	36 hrs., $2,388
IRO-014-3	11 (RC)	1	11	12 hrs. $796	132 hrs., $8,758	12 hrs., $796
IRO-017-1	180 (RC, PC, & TP)	1	180	218 hrs. $14,464	39,240 hrs., $2,603,574	218 hrs., $14,464
Sub-Total for FERC-725Z					42,540 hrs., $2,822,529.00	

[64] The number of respondents is the number of entities for which a change in burden from the current standards to the proposed exists, not the total number of entities from the current or proposed standards that are applicable.

[65] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of April 1, 2015, for an electrical engineer ($66.35/hour). These figures are *available at* http://bls.gov/oes/current/naics3_221000.htm#17-0000.

[66] IRO-001-4 is a revised standard with no increase in burden.

Retirement of current standards currently in FERC-725A	457(RC, TOP, BA, TSP, LSE, PSE, & IA)	1	457	-223 hrs. -$14,796	-101,911 hrs., -$6,761,794	-223 hrs. -$14,796
NET TOTAL of NOPR in RM15-16					**63,881 hrs, $3,993,540**	

Title: FERC-725Z, Mandatory Reliability Standards: IRO Reliability Standards, and FERC-725A, Mandatory Reliability Standards for the Bulk-Power System.

Action: Proposed Changes to Collections.

OMB Control Nos: 1902-0276 (FERC-725Z); 1902-0244 (FERC-725A).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: On-going.

72. Necessity of the Information and Internal review: The Commission has reviewed the requirements of Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 and made a determination that the standards are necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

73. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

74. Comments on the requirements of this rule may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk

Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference OMB Control Nos. 1902-0276 (FERC-725Z) and 1902-0244 (FERC-725A)) in your submission.

IV. Environmental Analysis

75. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[67] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[68] The actions approved herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

76. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities. [69] The Small Business Administration's (SBA) Office of Size

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[67] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[68] 18 C.F.R. 380.4(a)(2)(ii).

[69] 5 U.S.C. 601-12.

Standards develops the numerical definition of a small business.[70] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[71] Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 are expected to impose an additional burden on 196 entities (reliability coordinators, transmission operators, balancing authorities, transmission service providers, and planning authorities). Comparison of the applicable entities with the Commission's small business data indicates that approximately 82 of these entities are small entities that will be affected by the proposed Reliability Standards.[72] As discussed above, Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 will serve to enhance reliability by imposing mandatory requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The Commission estimates that each of the small entities to whom the proposed Reliability Standards TOP-001-3, TOP-002-4,

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[70] 13 C.F.R. 121.101.

[71] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

[72] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 750 employee threshold for each affected entity to conduct a comprehensive analysis.

TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 applies will incur costs of approximately $147,364 (annual ongoing) per entity. The Commission does not consider the estimated costs to have a significant economic impact on a substantial number of small entities.

VI. Document Availability

77. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

78. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

79. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

80. This final rule is effective **[insert date 60 days from publication in Federal Register]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.