NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

July 6, 2021

VIA ELECTRONIC FILING

Mr. Patrick Wruck, Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
V6Z 2N3

Re: *North American Electric Reliability Corporation*

Dear Mr. Wruck:

The North American Electric Reliability Corporation ("NERC") hereby submits Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standards Related to Establishing and Communicating System Operating Limits. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to this filing.

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

Sincerely,

/s/ Lauren Perotti

Lauren Perotti
Senior Counsel for the North American Electric Reliability Corporation

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

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

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED RELIABILITY STANDARDS RELATED TO ESTABLISHING AND COMMUNICATING SYSTEM OPERATING LIMITS

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NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED RELIABILITY STANDARDS RELATED TO ESTABLISHING AND COMMUNICATING SYSTEM OPERATING LIMITS

The North American Electric Reliability Corporation ("NERC") hereby submits the following proposed Reliability Standards:

- FAC-011-4 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 – Establish and Communicate System Operating Limits
- FAC-003-5 – Transmission Vegetation Management
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 – Transmission Operations

NERC also provides notice of (1) the retirement of Reliability Standard FAC-010-3 – System Operating Limits Methodology for the Planning Horizon; and (2) modifications to the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")[1] to revise the definition for System Operating Limit ("SOL") and include a new term, System Voltage Limit.

The proposed Reliability Standards and NERC Glossary terms, as shown in Exhibit A, and the retirement of currently effective Reliability Standard FAC-010-3, are just, reasonable, not

[1] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the NERC Glossary, available at https://www.nerc.com/files/Glossary_of_Terms.pdf.

unduly discriminatory or preferential, and in the public interest. NERC also provides notice of: (i) the associated Violation Risk Factors and Violation Severity Levels (Exhibit G) and (ii) the proposed implementation plan (Exhibit B). This filing presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the proposed Reliability Standards meet the Reliability Standards criteria (Exhibit F), and a summary of the standard development history (Exhibit H).

This filing is organized as follows: Section I provides an introduction to the proposed modifications to NERC's Reliability Standards and the NERC Glossary. Section II provides the individuals to whom notices and communications related to the filing should be provided. Section III provides the development of the proposed Reliability Standards and NERC Glossary terms. Section IV of the filing provides justification for the proposed Reliability Standards, NERC Glossary terms, and retirements. Section V of the filing provides a summary of the proposed implementation plan.

I. INTRODUCTION

The modifications proposed herein are designed to improve the framework for establishing and communicating SOLs. The use of SOLs is a foundational construct in NERC's Reliability Standards for providing for the reliable operation of the Bulk-Power System ("BPS"). Under the NERC Reliability Standards, SOLs serve as the parameters within which the Bulk Electric System ("BES") should be operated to provide for reliable pre- and post-contingency System performance. As discussed further below, SOLs constitute the Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in BES operations for monitoring and assessing pre- and post-Contingency operating states.

As submitted on March 25, 2015,[2] the Transmission Operations ("TOP") and Interconnection Reliability Operations ("IRO") Reliability Standards require Reliability Coordinators and Transmission Operators to plan to and operate within all SOLs, including the subset of SOLs that qualify as Interconnection Reliability Operating Limits ("IROLs"). Under those Reliability Standards, Transmission Operators and Reliability Coordinators must continually assess projected system conditions within the operations time horizon with the objective of ensuring acceptable system performance in Real-time. Specifically, Transmission Operators and Reliability Coordinators must perform Operational Planning Analyses ("OPAs"), Real-time Assessments ("RTAs"), and Real-time monitoring to assess anticipated (pre-Contingency) and potential (post-Contingency) operating conditions. The TOP/IRO Reliability Standards then require Transmission Operators and Reliability Coordinators to develop an Operating Plan to address any potential or actual SOL exceedances identified as a result of an OPA, RTA, or Real-time monitoring and, when necessary, initiate that Operating Plan to mitigate any identified SOL exceedances.

The Facilities Design, Connections, and Maintenance ("FAC") Reliability Standards include requirements for establishing and communicating SOLs and are thus integral in providing for reliable operations. The proposed Reliability Standards and NERC Glossary definitions would enhance those FAC standards by, among other things:

- providing for greater clarity and uniformity in Reliability Coordinators' SOL methodologies;
- improving the coordination between planning and operations as it relates to analysis input assumptions and System performance criteria;

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[2] *Notice of Filing of the North American Electric Reliability Corporation of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards,* (2015).

- establishing a performance framework for determining SOL exceedances when performing OPAs, RTAs, and Real-time monitoring;
- clarifying functional entity responsibilities for establishing and communicating each type of SOL and IROL, consistent with the Federal Energy Regulatory Commission's ("FERC") directive in Order No. 777;[3] and
- reducing redundancy and improving alignment with the Transmission Planning ("TPL"), TOP, and IRO Reliability Standards.

As discussed below, the proposed Reliability Standards and NERC Glossary terms are just, reasonable, not unduly discriminatory, and in the public interest and would enhance the framework for ensuring reliable operations.

II. NOTICES AND COMMUNICATIONS

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

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III. BACKGROUND

1. NERC Reliability Standards Development Procedure

The proposed modifications to NERC's Reliability Standards and NERC Glossary were developed in an open and fair manner and in accordance with the Reliability Standard development process. NERC develops Reliability Standards in accordance with Section 300 (Reliability

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[3] *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 at PP 6, 41 (2013) [hereinafter Order No. 777].

Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual ("SPM").[4]

NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards, and thus satisfy several of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees ("Board") must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the applicable governmental authorities.

2. Development History: Project 2015-09 Establish and Communicate SOLs

The modifications to the NERC Reliability Standards and NERC Glossary proposed herein were developed in Project 2015-09 Establish and Communicate System Operating Limits ("Project 2015-09"). Project 2015-09 was initiated to address recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. That periodic review, referred to as Project 2015- 03 Periodic Review of System Operating Limit Standards ("Project 2015-03"), was initiated according to section 13 of the SPM.[5]

The Project 2015-03 team recommended a number of revisions to the FAC-010, FAC-011, and FAC-014 Reliability Standards intended, in large part, to align the FAC Reliability Standards with new or modified TPL, TOP, and IRO Reliability Standards that either did not exist at the time that the three FAC standards were drafted or were modified significantly since that time. The primary recommendations of the Project 2015-03 periodic review team included the following:

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[4] The NERC Rules of Procedure, including Appendix 3A, NERC Standard Processes Manual, are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[5] Section 13 of the SPM requires that NERC review all Reliability Standards at least once every ten years to evaluate whether the Reliability Standard should be reaffirmed, revised, or withdrawn.

- Retire Reliability Standard FAC-010-3, which requires the development of an SOL methodology for the planning horizon. The periodic review team concluded the BES planning process is comprehensively covered under the new TPL-001-4 Standard.

- Revise requirements in FAC-011-3 and FAC-014-2 as the current language contributes to confusion and a lack of consistency in establishing, communicating, and operating within SOLs.

- Revise the SOL definition to align with the concepts described in the NERC System Operating Limit Definition and Exceedance Clarification White Paper developed by the standard drafting team for Project 2014-03 Revisions to TOP and IRO Standards.[6]

- Revise the requirements in FAC-011 to clarify acceptable System performance criteria for the operations horizon through the Reliability Coordinator's SOL methodology.

- Revise FAC-014-2 to delete references to planning horizon SOLs and clearly delineate specific functional entity responsibility for determining and communicating each type of SOL used in operations.

- Provide additional clarification on which SOLs qualify as IROLs.[7]

NERC initiated Project 2015-09 to evaluate the recommendations of the periodic review.[8] NERC also included within the scope of Project 2015-09 (1) FERC's directive in Order No. 777 to "establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners"[9] and (2) FERC's directive in Order No. 817 to address regional discrepancies in methods for establishing IROLs.[10]

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6 The Project 2014-03 White Paper is available at https://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf.

7 Additional information regarding Project 2015-03 is available at https://www.nerc.com/pa/Stand/Pages/Project-2015-03-Periodic-Review-of-System-Operating-Limit-Standards.aspx.

8 The Project 2015-09 Standard Authorization Request for Project 2015-09 is available at https://www.nerc.com/pa/Stand/Project%20201509%20Establish%20and%20Communicate%20System%20Op/2015-09_SAR_Revision_Clean_092717.pdf.

9 Order No. 777 at P 41.

10 *See Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015) [hereinafter Order No. 817]. In Order No. 817, which approved the TOP and IRO standards, FERC discussed regional differences in establishing IROLs. It decided not to direct further action on IROLs in that rulemaking, finding that it should be addressed in Project 2015-09. FERC stated that "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 FERC's directive in Order No. 802 (approving Reliability Standard CIP-014) to eliminate or clarify the 'widespread' qualifier on 'instability' as well as

As detailed below, the Project 2015-09 standard drafting team ("SDT") (1) developed proposed revisions to Reliability Standards FAC-011, FAC-014, IRO-008, and TOP-001-6; (2) proposed the retirement of FAC-010-3 and developed corresponding revisions in the FAC-003, PRC-002, PRC-023, and PRC-026-2 Reliability Standards to remove or replace references to SOLs established by planning entities, and (3) proposed modifications to the NERC Glossary definition of SOL and developed a new NERC Glossary term, System Voltage Limit. The NERC Board adopted the proposed Reliability Standards, NERC Glossary terms, and retirements on May 13, 2021. A summary of the development history and the complete record of development is attached to this filing as Exhibit H.

3. Order No. 817 Directive Regarding Establishing IROLs

As noted above, the scope of Project 2015-09 initially included a review of the manner in which IROLs are established to address, among other things, the regional discrepancies discussed in Order No. 817. The Project 2015-09 SDT considered potential revisions to the IROL definition and requirements in the FAC standards to improve consistency in the manner Reliability Coordinators establish IROLs. After many meetings with stakeholders, however, the SDT concluded that additional data, analysis, and discussion on the topic of IROLs was necessary before it could properly address the issue and reach consensus.

As a result, NERC, together with the Standards Committee, determined that it would be beneficial to develop additional technical information on the establishment of IROLs prior to engaging in any further development of modifications to the IROL definition or FAC requirements. NERC, with Standard Committee authorization, separated the IROL issues from

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our statement in the Remand NOPR [leading up to Order No. 817] that 'operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability.'" Order No. 817 at P 27.

Project 2015-09, with the exception of IROL communication issues discussed in Order No. 777, and requested that NERC's technical committees, the Operating Committee ("OC") and Planning Committee ("PC"), form a joint task force, comprised of both operating and planning subject matter experts, to develop technical material for the IROL-related issues.[11] The objective was for this technical material to be used by industry as a resource to enhance the manner in which Reliability Coordinators establish certain IROLs and inform any future Reliability Standard development activity. The OC and PC established the task force, referred to as the Methods for Establishing IROLs Task Force ("MEITF").

The MEITF has since issued a number of documents to guide industry and inform any future development activity. In September 2018, the MEITF drafted a Reliability Guideline, approved by NERC's technical committees, to provide guidance to industry on the development of technically sound methods for establishing IROLs.[12] The guideline provides detailed technical reference material related to the assessment of system instability, uncontrolled separation, and Cascading to ensure the reliable operation of the BPS. Each of the three concepts related to Reliable Operation are discussed in depth, including analysis techniques and considerations that should be made when determining how they may contribute to the establishment of an IROL. Recommended practices and techniques are described using example simulations and actual system studies to clearly articulate the concepts. The various facets of establishing IROLs are described in sufficient detail to promote consistency in terminology and analysis techniques.

[11] The OC and PC have since been subsumed into the Reliability and Security Technical Committee.

[12] The Reliability Guideline is available at https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf.

The MEITF also issued an IROL Framework Assessment Report, outlining alternative frameworks for establishing IROLs under the NERC Reliability Standards. It also drafted recommendations on potential changes to the NERC Glossary and Reliability Standards to align with those frameworks.[13]

At this time, NERC continues to evaluate the MEITF's framework and recommendations and monitor the impact of the MEITF's Reliability Guideline on the regional discrepancies discussed in Order No. 817. Prior to initiating any formal standards development project to consider the recommendations of the MEITF and address the outstanding directive in Order No. 817, NERC will gather additional data through its compliance monitoring activities on: (1) whether and how Reliability Coordinators have revised their methods for establishing IROLs in response to the Reliability Guideline; and (2) whether the revised methods have resulted in a more consistent approach to establishing IROLs across the BPS. If NERC observes that significant regional discrepancies persist, and those discrepancies do not appear to be justified by the unique characteristics of the region, NERC would initiate a formal standards project to evaluate those issues. As NERC gathers data and conducts this evaluation, it will consult with FERC staff.

IV. JUSTIFICATION

The proposed Reliability Standards and NERC Glossary terms meet the Reliability Standards criteria and are just, reasonable, not unduly discriminatory, and in the public interest. As discussed more fully below, the proposed standards will enhance reliability by improving the framework for establishing and communicating SOLs and improving alignment between the FAC, TPL, TOP, and IRO Reliability Standards. Collectively, the proposed modifications to the NERC Glossary and Reliability Standards support the ultimate purpose of the SOL construct: (1)

[13] The MEITF's proposed framework, recommendations and other documents are available at: https://www.nerc.com/comm/PC/Pages/Methods-for-Establishing-IROLs-(MEITF).aspx.

establishing the applicable Facility Ratings, voltage limits, transient stability criteria, and voltage stability criteria through a common methodology, (2) ensuring that they are all observed in assessments of both the pre- and post-Contingency state when performing OPAs, RTA, and Real-time monitoring, and (3) developing and implementing Operating Plans to address any SOL exceedances observed during such assessments.[14]

1. Overview of Proposed Framework for Establishing and Communicating SOLs

The requirements to establish and communicate SOLs in the FAC-010, FAC-011, and FAC-014 Reliability Standards are inextricably linked to the TPL, TOP, and IRO standards. Each group of standards address the foundational reliability concept of planning for and ensuring acceptable system performance during operations. While the SOL definition and the FAC standards have remained essentially unchanged since their initial versions were submitted, there has been significant changes to the TPL, TOP, and IRO standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with a single comprehensive planning standard, TPL-001-4;[15] all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003 Reliability Standards; and several IRO standards have been

[14] As used in the proposed SOL definition and FAC standards, and the currently effective TOP/IRO standards, the pre-Contingency state is synonymous with the actual or initial state of the system. For Real-time monitoring and RTAs, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies. The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis. Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. References to the post-Contingency state or post-Contingency flows or voltages, are thus referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

[15] On December 14, 2018, NERC submitted TPL-001-5, which modified the TPL-001 standard. *See Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standard TPL-001-5, (*2018).). The modified version of the standard, TPL-001-5, will become effective in 2023.

substantially modified. The proposed modifications to the NERC Glossary and Reliability Standards would enhance the framework for establishing and communicating SOLs and reflect the new constructs in the TPL, TOP, and IRO standards.

The following is an overview of the proposed framework for establishing and communicating SOLs:

Time Horizon for SOLs: To reflect the comprehensive transmission planning requirements in TPL-001-4, the proposed framework discussed in this filing would only require the establishment and use of SOLs in the operating horizon. Under currently effective Reliability Standards FAC-010-3 and FAC-014-2, each Planning Coordinator and Transmission Planner must establish a set of SOLs and IROLs for the planning time horizon based on the Planning Coordinator's SOL methodology. The Project 2015-09 SDT concluded that it was unnecessary to require planning entities to establish SOLs for the planning horizon given the comprehensive transmission planning requirements in TPL- 001- 4. Reliability Standard TPL-001-4 is designed to establish comprehensive Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. Reliability Standard TPL-001-4 requires planning entities to establish the applicable limits or criteria for their Planning Assessments.

NERC is thus proposing to retire Reliability Standard FAC-010-3 – which relates entirely to SOLs for the planning horizon – and modify Reliability Standards FAC-003, PRC-002, PRC-023, and PRC-026 to remove or replace references to planning horizon SOLs or IROLs. To enhance alignment between planning and operations, NERC is also proposing to include requirements in proposed Reliability Standards FAC-011-4 and FAC- 014- 3 to improve the coordination of analysis input assumptions and System performance criteria between the Planning Assessments required in TPL-001-4 and the establishment of SOLs used in operations.

SOL Methodologies: As in the currently effective FAC Reliability Standards, the framework for establishing operating SOLs begins with the development of an SOL methodology. An SOL methodology helps ensure that SOLs are determined based on a common, established methodology across an entire Reliability Coordinator Area. Pursuant to proposed Reliability Standard FAC-011-4, Reliability Coordinators would continue to be responsible for developing a methodology for establishing SOLs (including IROLs) for use in operations in its area.

To improve uniformity in establishing SOLs, proposed FAC-011-4 improves upon the currently effective version of the standard by requiring Reliability Coordinators to provide for the following in their SOL methodologies: (1) the method for Transmission Operators to determine which Transmission Owner-provided Facility Ratings to use during operations (Requirement R2), (2) the methods to determine System Voltage Limits and stability limits (Requirements R3-R4), and (3) the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing OPAs and RTAs (Requirement R5).

NERC is also proposing a modified definition of the term SOL in the NERC Glossary to help ensure SOLs are easily identifiable and measurable, and which aligns with the SOL construct in the TOP and IRO standards. NERC proposes to define SOLs as "all Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states."

Determining SOL Exceedances: Another key component of the proposed SOL framework is setting the performance criteria used to determine SOL exceedances. Under currently effective

FAC-011-3, Requirement R2, the Reliability Coordinator's SOL methodology must include a requirement that SOLs provide BES performance consistent with certain pre-Contingency performance criteria, post-Contingency performance criteria, and other rules related to the establishment of SOLs. Under this construct, assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria in Requirement R2.

These existing requirements were developed in 2007 in conjunction with the then-effective TOP/ IRO standards to create the following construct for reliable operations:

- Transmission Operators and Reliability Coordinators would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
- If the studies indicated that any of the performance criteria (in FAC-011-3, Requirement R2) were not met, the Transmission Operator would establish an SOL which, if operated within, would result in meeting all of the performance criteria.
- The Transmission Operator would then operate the system within those SOLs to ensure acceptable System performance.

Prior to April 1, 2017, when the modifications to the TOP/IRO standards submitted on March 25, 2015became effective, the TOP/IRO standards did not require entities to perform assessments of the post-Contingency state in same-day or Real-time operations. The requirements associated with assessments of the post-Contingency state were essentially folded into the SOL establishment process – i.e., the establishment of SOLs that "provide" for meeting the pre- and post-Contingency performance criteria in FAC-011-3, Requirement R2.

The currently effective TOP/IRO standards, however, provide a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct, Transmission Operators and Reliability Coordinators are required to perform OPAs in the day-ahead time frame to assess whether the planned operations for the next day will exceed any of

SOLs or IROLs.[16] The pre- and post-Contingency states are analyzed as part of the OPA. If the OPA identifies any potential SOL exceedances, the Transmission Operator and Reliability Coordinator must have an Operating Plan to address those exceedances.[17]

In Real-time, Transmission Operators and Reliability Coordinators must perform RTAs at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[18] The pre- and post-Contingency states are analyzed as part of the RTA. If a Transmission Operator observes an SOL exceedance in its Real-time monitoring or RTA, the Transmission Operator is required to implement its Operating plan to mitigate the conditions.[19] If a Reliability Coordinator observes an SOL or IROL exceedance in its Real-time monitoring or RTA, the Reliability Coordinator is required to notify the relevant Transmission Operators of the exceedance so the Transmission Operator can address it.[20] If the Reliability Coordinator identifies an expected or actual IROL exceedance in its Real-time monitoring or RTA, the exceedance must be resolved within the IROL Tv, which can be no longer than 30 minutes.[21]

Accordingly, pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, Transmission Operators and Reliability Coordinators must continually assess system conditions, identify expected or actual SOL exceedances (including IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. The pre- and post-Contingency states are thus assessed on an ongoing basis as part of OPAs and RTAs.

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16 IRO-008-3, Requirement R1; TOP-002-4, Requirement R1.
17 IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.
18 IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.
19 TOP-001-3, Requirement R14.
20 IRO-008-2, Requirement R5.
21 IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

To align with this new construct, proposed FAC-011-4, Requirement R6 requires Reliability Coordinators to include in their SOL methodologies a specified performance framework to determine SOL exceedances when performing Real-time monitoring, RTAs, and OPAs. The proposed performance framework would help ensure there is consistency in determining what constitutes an SOL exceedance during operations. The performance framework maps to and clarifies the performance criteria in currently effective FAC-011-3, Requirement R2.

NERC is also proposing new requirements in IRO-008-3 and TOP-001-6 to require Reliability Coordinators and Transmission Operators to use the SOL exceedance performance framework in the Reliability Coordinator's SOL methodology when performing Real-time monitoring, RTAs, and OPAs. Additionally, under proposed FAC-011-4, to ensure that SOL exceedances are communicated in a timely manner, the Reliability Coordinator must also include in its SOL methodology a risk-based approach for determining how and when SOL exceedances identified as part of Real-time monitoring and RTAs must be communicated.

Communicating SOL Methodologies: The next step in the process of establishing SOLs is for the Reliability Coordinator to distribute its SOL methodology to the appropriate entities, namely, those entities responsible for developing SOLs within the Reliability Coordinator Area and those that should otherwise have awareness of the manner in which SOLs are developed in that area given their functional obligations. As discussed below, proposed FAC-011-4, Requirement R9 specifies the entities to which the Reliability Coordinators must provide its SOL methodology and the timeframe for doing so.

Responsibility for Establishing SOLs: Once the Reliability Coordinator develops and communicates the SOL methodology, the next part of the framework is for the appropriate entities to use that methodology to establish the SOLs used in operations. Proposed Reliability Standard

FAC-014-3 delineates the functional entities responsible for establishing and communicating each type of SOL. As discussed further below, each Transmission Operator is obligated to establish SOLs for its portion of the Reliability Coordinator Area, with one exception. The Reliability Coordinator is responsible for establishing stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area. Reliability Coordinators are also responsible for establishing IROLs for its area.

Responsibility for Communicating SOLs: The last element of the proposed framework is communicating the established SOLs. Under proposed Reliability Standard FAC-014-3, each Transmission Operator must provide its SOLs to their Reliability Coordinator. In turn, Reliability Coordinators are responsible for providing the SOLs (including IROLs) for its area to Planning Coordinators, Transmission Planners, and Transmission Operators. The proposed requirements improve upon the current standards by clarifying when the Reliability Coordinator is responsible for such communications. The proposed requirement addresses both the content and the frequency at which the information must be provided and complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information.

The following is a more detailed discussion of each of the proposed modifications to the NERC Glossary and Reliability Standards.

2. Proposed Modification to Definition for System Operating Limit

The proposed SOL definition is designed to provide greater clarity and consistency in establishing SOLs.[22] The Project 2015-9 SDT found that although use of SOLs is a foundational

[22] Available at https://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf.

concept in NERC's Reliability Standards, there were significant discrepancies in registered entities' understanding and application of SOLs. SOL is currently defined 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 Ratings 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).

The Project 2015-09 SDT proposed the following SOL definition to eliminate ambiguities and provide for a more straightforward approach to facilitate a more consistent application of the SOL concept across the electricity industry:

> All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

The proposed definition retains Facility Ratings, voltage limits, and stability limits as the types of operating parameters that would be categorized as SOLs. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. For voltage limits, the proposed SOL definition uses a new term proposed to be incorporated into the NERC Glossary, System Voltage Limit. As discussed further below, the proposed definition for System Voltage Limit is "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Proposed FAC-011-4 addresses the method for determining System Voltage Limits to be used in operations.

Stability limits includes both transient stability limits and voltage stability limits as in the currently effective definition. NERC proposes to use the undefined term "stability limit," as opposed to the NERC Glossary term "Stability Limit," to allow entities to use different types of stability-related limitations or phenomena, including, but not limited to, subsynchronous resonance, phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio. The NERC Glossary term "Stability Limits" is limited to a maximum power flow value. While some entities use maximum power flow values as a means by which to prevent instability, this approach represents one method and may be too restrictive for some entities. Reliability tools provide entities the ability to monitor and control parameters other than maximum power flow to demonstrate acceptable stability performance.

The proposed SOL definition also retains the reference to "specified system configuration." Stability limits are typically dependent on system configuration and, although not typical, Facility Ratings and System Voltage Limits may also be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for the line could be reduced due to the current carrying capability of the remaining in-service circuit breaker.

There are a number of key differences between the currently effective SOL definition and the proposed definition. Whereas the currently effective SOL definition states that SOLs "are based upon certain operating criteria," the proposed definition clarifies that SOLs "are" the actual operating parameters to be observed for the pre- and post-Contingency states. This change helps eliminate confusion as to whether a Facility Rating, stability limit, or voltage limit is an SOL.

In contrast to the existing definition, the proposed definition also includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning from those used in operations. As discussed below, NERC is proposing to retire FAC-010-3 and the requirements related to the establishment and communication of planning horizon SOLs. The SDT concluded that planning horizon SOLs are unnecessary given the comprehensive planning requirements in TPL-001-4. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there is no additional reliability need to require planning entities to develop SOLs to be used in the planning horizon.

NERC also proposes removing the "most limiting criteria" concept from the SOL definition. Under the modified definition, all Facility Ratings, System Voltage Limits, and stability limits are considered SOLs. This change aligns with the requirements in the TOP/IRO Reliability Standards. As noted above, under those standards, each Reliability Coordinator and Transmission Operator must perform OPAs and RTAs to assess conditions in the day-ahead and Real-time time horizons. The currently effective SOL definition requires Reliability Coordinators and Transmission Operators to initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT found that this construct was unnecessary and caused confusion within industry as the most limiting criteria (and thus the SOL) could change from one RTA to the next.

The SDT determined that a more straightforward approach – categorizing all Facility Ratings, System Voltage Limits, and stability limits as SOLs – would align more clearly with the TOP/IRO standards. In performing OPAs and RTAs, Reliability Coordinator and Transmission Operator should be assessing conditions as it relates to all of these operating parameters or reliability limits, not just the most limiting parameter or limit based on a particular prior analysis. In assessing conditions to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, Reliability

Coordinators and Transmission Operators would capture the most limiting of those parameters/limits. The "most limiting criteria" concept is thus subsumed within the IRO/TOP requirements and it is not necessary that it be included in the SOL definition.

The "most limiting criteria" in the SOL definition could also mask instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot safely conclude that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria," it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the Reliability Coordinator and its Transmission Operators have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL methodology.

NERC also proposes to remove the "acceptable reliability criteria" concept from the SOL definition. The SDT concluded that acceptable reliability criteria is best addressed in the body of the Reliability Standards and the SOL definition should focus exclusively on what constitutes an SOL. Operations performance criteria is addressed in proposed FAC-011-4, Requirement R6.

Last, the proposed SOL definition retains the pre- and post-Contingency concept, although the reference is modified to align with the construct in the currently effective TOP/IRO standards. The proposed definition recognizes that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability

Standards for determining potential SOL exceedances and actual SOL exceedances, respectively, the definition of SOL should support the concept that entities must account for both the pre- and post-Contingency states.

3. Proposed NERC Glossary Term System Voltage Limit

NERC also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

The proposed definition would help provide for a uniform understanding as to what constitutes a system voltage limit. The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single maximum and minimum limit that is applicable to its entire system. Rather, as explained below, under proposed FAC-011-4, Requirement R3, the Reliability Coordinator's SOL methodology would dictate the manner in which System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to provide flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL methodology. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. Last, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating because proposed FAC-011-4, Requirement R3 requires that System Voltage Limits respect voltage-based Facility Ratings.

4. Proposed Retirement of Reliability Standard FAC-010-3 and Modifications to Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2

As noted above, NERC is proposing to retire Reliability Standard FAC-010-3 to remove the requirements that Planning Coordinators and Transmission Planners establish SOLs for the planning horizon. This section explains the rationale for the proposed retirement and describes the modifications to Reliability Standards FAC-003, PRC-002, PRC-023, and PRC-026 to remove or replace references to planning horizon SOLs or IROLs. This section also provides the rationale for not proposing modifications to Reliability Standards CIP-002-5.1a or CIP-014-2, although those standards also reference planning horizon IROLs. As explained below, the retirement of FAC-010-3 is not dependent on modifying those Critical Infrastructure Protection ("CIP") standards. Given the unique expertise required for the CIP standards, it is prudent to allow a CIP-specific SDT to address any conforming changes to those standards.

i. <u>Retirement of FAC-010-3</u>

As noted above, the SDT concluded that the requirements related to the establishment and communication of planning horizon SOLs in FAC-010-3 and FAC-014-3 were unnecessary for reliability given the comprehensive planning requirements in TPL-001-4. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 (Facility Ratings) and TPL-001-4 (voltage limits, and stability criteria). As a result, there was no additional reliability need to require Planning Coordinators and Transmission Planners to develop SOLs to be used in the planning horizon.

Exhibit D-1 to this filing provides a mapping of the existing requirements in FAC- 010-3 to TPL-001-4. As illustrated therein, all of the reliability issues that FAC-010-3 was intended to cover have since been addressed in TPL-001-4, as follows:

FAC-010-3, Requirement R1 requires Planning Authorities to have a methodology for developing SOLs within its area applicable to the planning horizon. The determination of Facility Ratings, System steady- state voltage limits, and stability performance criteria for use in the planning horizon, however, are now fully addressed in TPL-001-4:

- Facility Ratings – TPL-001-4, Requirement R1, requires Planning Coordinators and Transmission Planners to maintain System models and to use data consistent with that which has been provided in accordance with MOD- 032- 1. Facility Ratings, as determined under FAC-008-3, are included in this data.
- System Steady- State Voltage Limits – TPL- 001- 4, Requirement R5 requires the Transmission Planner and Planning Coordinator to have criteria for acceptable System steady state voltage limit to be used in the Planning Assessments.
- Transient and Voltage Stability Performance Criteria – TPL- 001- 4, Requirement R6 requires the Transmission Planner and Planning Coordinator to have documented criteria to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

FAC-010-3, Requirement R1 also requires Planning Authorities to include in their SOL methodologies a description of how to identify IROLs, which is defined as an SOL "that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." While TPL-001-4 does not use the term IROL, the functional equivalent of IROLs must be identified in the Planning Assessment. TPL- 001- 4, Requirement R6 requires Planning Coordinators and Transmission Planners to document criteria or a methodology for use in identifying System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. The Planning Assessment is shared with impacted Reliability Coordinators, per IRO-017-1 Requirement R3. Additionally, the Planning Assessment must identify instances of instability, Cascading or uncontrolled separation. The identified instances must be communicated to the Reliability Coordinator in accordance with FAC-014-3, Requirement R7 along with additional information about those instances.

FAC-010-3, Requirement R2 requires that the Planning Authority's SOL methodology include a requirement that SOLs provide BES performance consistent with certain specified criteria. The specified criteria maps to the performance requirements contained in Table 1, notes a–j, of TPL-001-4. The Table 1 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment. As demonstrated in Exhibit D-1, the FAC-010-3 pre-Contingency performance criteria, the post-Contingency performance criteria, and other rules are addressed in Table 1 of TPL-001-4.

FAC-010-3, Requirement R3 requires that the SOL methodology include a description of the following: study model, selection of applicable Contingencies, level of detail of system models used to determine SOLs, allowed uses of Remedial Action Schemes, anticipated transmission system configuration, generation dispatch and Load level, and the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL Tv. As demonstrated in Exhibit D-1, each of these items is covered in TPL-001-4.

FAC-010-3, Requirement R4 requires the Planning Authority to provide its SOL methodology, and any change thereto, to adjacent Planning Authorities, other Planning Authorities with a reliability-related need for it, Reliability Coordinators and Transmission Operators that operates any portion of the Planning Authority Area, and Transmission Planners in the Planning

Authority Area. The TPL-001-4 Planning Assessment must also be distributed to those same planning entities (under TPL-001-4, Requirement R8) and impacted Reliability Coordinators (under IRO-017-1, Requirement R3). Other entities with a reliability-related need, which reasonably includes Transmission Operators, among others, may also receive the Planning Assessment (under TPL-001-4, Requirement R8).

While TPL-001-4 obviates the need for planning horizon SOLs, the SDT concluded there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT therefore developed requirements in proposed Reliability Standards FAC-011-4 and FAC-014-3 to address that issue. Those requirements, discussed in greater detail in Section IV.5-6 below, enhance the coordination of analysis input assumptions and System performance criteria between the Planning Assessments required in TPL-001-4 and the establishment of SOLs to be used in operations.

i. <u>Proposed Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2</u>

With the proposed retirement of FAC-010-3, NERC is also proposing modifications to the FAC-003, PRC-002, PRC-023, and PRC-026 Reliability Standards to remove or replace references to planning horizon SOLs or IROLs. The following is a description of the modifications in proposed Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2.

<u>FAC-003-5</u> – NERC proposes to modify Applicability Sections 4.2.2 and 4.3.1.2 of FAC-003-5 to replace references to “elements of an IROL under NERC Standard FAC-014 by the Planning Coordinator” with references to facilities:

> identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near- Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

The reference to facilities "that if lost or degraded are expected to result in instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System" is the functional equivalent to referencing elements of a planning horizon IROL. An IROL is defined as a SOL "that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Additionally, NERC is proposing to delete the language referencing planning horizon SOLs from Requirement R1, as follows:

> Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s)~~, which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all Rated Electrical Operating Conditions of the types shown below.

NERC is also proposing to delete Requirement R2 in its entirety as it is redundant to Requirement R1. Requirements R1 and R2 are essentially the same requirements but apply to different Facilities. These requirements were initially separate to recognize that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a result, the Violation Risk Factor ("VRF") was set at "high" for Requirement R1 and "medium" for Requirement R2. In FERC Order 777, however, FERC directed NERC to change the VRF for Requirement R2 from "medium" to "high" because transmission lines that were not part of an IROL or Major WECC Transfer Path contributed to cascading outages in the past.[23] This removed the only difference

[23] Order No. 777 at P 77.

between the two Requirements R1 and R2, resulting in redundancy between the two requirements. NERC is therefore proposing the retirement of Requirement R2 with the modifications to Requirement R1 to apply to all applicable facilities.

PRC-002-3 – NERC proposes to modify the applicability of the PRC-002 standard to remove Planning Coordinators as a responsible entity subject to the standard and replace any references in the standard that would have included Planning Coordinators with references to Reliability Coordinators. The SDT concluded that the Reliability Coordinator was the appropriate entity to carry out the duties that currently apply to Planning Coordinators in certain interconnections, including the identification of BES elements that are part of an IROL or stability-related SOL.

PRC-023-5 – NERC proposes to modify Section B2 of Attachment B to PRC-023-5 as follows:

> B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events. ~~The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

Attachment B sets the criteria used to determine the circuits in a Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with certain requirements in the standard applicable to protective relays.

PRC-026-2 – NERC proposes modification to the PRC-026 standard to replace references to planning horizon SOLs with references to the TPL-001-4 Planning Assessment, as follows:

> R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner:

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator ~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. ~~An~~ Elements associated with ~~that is monitored as part of an SOL identified by the Planning Coordinator's methodology based~~ on an angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event ~~constraint~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance for a planning event. [footnote omitted]

ii. CIP-002 and CIP-014

As noted above, both CIP-002-5.1a and CIP-014-2 reference planning horizon IROLs. The CIP-002 Reliability Standard requires entities to identify and categorize their BES Cyber Systems as high, medium, or low impact based on the criteria set out in Attachment 1 to the standard. Criterion 2.6 in Attachment 1 provides that BES Cyber Systems associated with the following should be categorized as medium impact:

> Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

Similarly, the applicability section for CIP-014 provides that a Transmission Owner that owns a substation that meets the following criteria, among others, is subject to the standard:

> 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

At this time, however, NERC is not proposing modifications to Reliability Standards CIP-002-5.1a or CIP-014-2 to remove or replace references to planning horizon IROLs. Given the unique expertise required for the development of CIP standards, it is prudent to allow a CIP-specific SDT to address any conforming changes to those standards as it considers other changes to the CIP-002 criteria and CIP-014 applicability.[24] When the NERC Board adopted the modifications proposed herein, it directed NERC staff to evaluate the need for conforming changes in CIP-002 and CIP-014.

On June 2, 2021, the Project 2015-09 SDT submitted a SAR to the NERC Standards Committee to initiate a formal development project to assess the need for any conforming changes to CIP-002 or CIP-014. The Standards Committee may add it to the scope of Project 2021-03, which is currently addressing modifications to CIP-002, or initiate a separate project.

As explained in Exhibit C-7, the retirement of FAC-010-3 may proceed prior to making any conforming changes to CIP-002 or CIP-014. The retirement of FAC-010-3 is not expected to decrease the protections of critical facilities under the CIP standards. Under the proposed FAC Reliability Standards, the Reliability Coordinator remains responsible for establishing IROLs for use in operations and would thus continue to identify transmission and generation facilities critical to the derivation of those IROLs and their associated contingencies under Criterion 2.6 in Attachment 1 to the CIP-002 Reliability Standard and for CIP-014 applicability.

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24 NERC initially posted for comment and ballot proposed conforming changes to the CIP-002 and CIP-014 standards to replace references to planning IROLs. The proposal for CIP-002 did not garner sufficient stakeholder support from the Registered Ballot Body. Based on stakeholder comments, NERC determined it was prudent to delay consideration of any such changes until a CIP-specific SDT was considering CIP-002 changes.

Proposed FAC-014-3 would enhance that identification in two ways. First, the proposed modifications in FAC-014-3 would help ensure that the Reliability Coordinator's identification of IROLs is informed by reliability risks identified by Planning Coordinators and Transmission Planners under TPL-001-4. Specifically, pursuant to proposed FAC- 014- 3, Requirements R7 and R8, Planning Coordinators and Transmission Planners must share with impacted Reliability Coordinators information on any instability identified in a TPL-001-4 Planning Assessment and the associated Corrective Action Plan ("CAP").[25] This sharing would include "their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES." These requirements would thus provide the Reliability Coordinator with additional relevant information it needs from planning entities in its determination of IROLs. From a CIP perspective, because of this improved communication, the Reliability Coordinator's list of facilities critical to the derivation of IROLs would likely cover many of the facilities that would have otherwise been identified by planning entities under Criterion 2.6 in Attachment 1.

Second, proposed FAC-014-3, Requirement R5, part 5.6, would require the Reliability Coordinator to provide each impacted Generator Owner or Transmission Owner with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. This requirement does not currently exist. There is currently no requirement that the information described in Attachment 1 of CIP-002.5.1a be provided to Transmission Owners or Generation Owners. Proposed FAC- 014-3,

[25] Under TPL- 001- 4 Requirement, R3, Parts 3.4 and 3.5, and Requirement R4 Parts 4.4 and 4.5, Planning Coordinators and Transmission Planners must identify and create a list of the planning and extreme events that are expected to produce "more severe System impacts." These events may significantly overlap with those events that are critical to the derivation of an IROL as they are based on the components of the IROL definition (instability, Cascading, and uncontrolled separation that adversely impact the reliability of the BES) to describe the relevant Facilities as opposed to using the term itself.

Requirement R5, Part 5.6 fills that gap by requiring the Reliability Coordinator to provide the information on a regular basis. This requirement addresses the concern in Order No. 777 regarding providing such information to asset owners subject to the CIP standards. With an annual submission, the Reliability Coordinator should be able to provide the required information whether the data is created in an annual process (such as seasonal studies), or some other effort with a higher periodicity.[26]

The retirement of FAC-010-3 is also unlikely to decrease the level of CIP protection as many of the facilities that would have been identified by Planning Coordinators and Transmission Planners under Criterion 2.6 are also covered by other criteria in Attachment 1 to CIP-002-5.1a and the applicability of CIP-014-2. Criterion 2.3, for instance, covers generation Facilities identified by Planning Coordinators and Transmission Planners as necessary to avoid an Adverse Reliability Impact. The definition of Adverse Reliability Impact is "the impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." Given the similarity with the definition of IROL, there is significant overlap between the generation Facilities subject to Criterion 2.3 and those that the Planning Coordinators and Transmission Planner would identify as critical to the derivation of an IROL under Criterion 2.6.

Criterion 2.4 requires BES Cyber Systems associated with Transmission Facilities operated at 500 kV or greater voltages to be in the medium impact category. As these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one

[26] Additionally, pursuant to TPL-001-4, Requirement R8, Transmission Owners and Generation Owners may request the Planning Assessment from the relevant planning entity. The Planning Assessment will include a list of the planning and extreme events that are expected to produce "more severe System impacts." There would likely be significant overlap between the facilities relevant to those events and those that planning entities would have identified as critical to the derivation of an IROL under Criterion 2.6.

or more of these Facilities would generally produce more severe impacts than lower voltage Facilities. This criteria also significantly overlap with the Facilities that planning entities would have otherwise identified under Criterion 2.6.

Criterion 2.5, which is also in the applicability of CIP-014, applies to Transmission Facilities operating between 200 kV and 499 kV based on the number of connections to other Transmission stations or substations. The basic premise of this criterion is to categorize BES Cyber Systems associated with "well- connected" BES substations as medium impact. As these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than Facilities not as well connected to the System. This criteria would thus largely overlap with the Facilities that would otherwise be identified by planning entities under Criterion 2.6.

For these reasons, the retirement of FAC-010-3 would not result in any gap in the CIP standards. Consistent with the NERC Board's directive, however, NERC will initiate its stakeholder processes to evaluate conforming changes to remove or replace references to planning horizon IROLs in CIP-002 and CIP-014.

5. Proposed Reliability Standard FAC-011-4

The purpose of the FAC-011 Reliability Standard is to "ensure that [SOLs] used in the reliable operation of the [BES] are determined based on an established methodology or methodologies." The following is a description of each of the requirements of proposed FAC-011-4 and a discussion of the changes from the previous version of the standard.

<u>Requirement R1</u>: As in the currently effective version of FAC-011, proposed Reliability Standard FAC-011-4, Requirement R1 requires Reliability Coordinators to "have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator

Area." The remaining requirements in the proposed standard address the contents and communication of that methodology.

As described in the SDT's technical rationale (Exhibit C-1) and mapping document (Exhibit D-1) for proposed FAC-011-4, Requirement R1 does not include the three subparts in the current version. Those subparts are either not necessary for reliability, or they are addressed in other requirements in proposed FAC-011-4, as follows:

- Part 1.1 in the effective version, which specifies that the SOL methodology "be applicable for developing [SOLs] used in the operations horizon," is not necessary as the revised Requirement R1 already specifies that it is applicable to the Operations Planning Time Horizon.

- Part 1.2 in the effective version, which requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings," is addressed in proposed Requirement R2.

- Part 1.3 in the effective version, which requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs," is now addressed in proposed Requirement R8.

Requirement R2: Proposed Requirement R2 addresses Facility Ratings, and provides:

> Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

The FAC-008 Reliability Standard governs the establishment of Facility Ratings, requiring Transmission Owners and Generation Owners to establish Facility Ratings in accordance with a specified methodology and communicate those ratings to relevant entities. The reliability objectives of proposed FAC-011-4, Requirement R2 is to ensure that Reliability Coordinators and their Transmission Operators use the same owner-provided Facility Ratings in operations. For example, if a Transmission Owner provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another Transmission Owner provides five levels of ratings, proposed

Requirement R2 instructs the Reliability Coordinator to establish the method for determining which of those Facility Ratings must be used in operations for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner remains the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to ensure that those owner-provided Facility Ratings are used consistently between Reliability Coordinators and their Transmission Operators during operations.

Requirement R3: The reliability objective of proposed Requirement R3 is to ensure that System Voltage Limits are determined according to an established method that meets certain criteria. The currently effective version does not include such a requirement. Requirement R3 provides as follows:

> **R.3.** Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:
>
> 3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
>
> 3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;
>
> 3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;
>
> 3.4. Identify the minimum allowable System Voltage Limit;
>
> 3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

Requirement R3 Part 3.1 provides that each BES bus/station have an associated System Voltage Limit, unless otherwise specified in the SOL methodology. The SDT concluded that while all BES buses/stations have equipment-related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from maximum voltage, and the System from instability, voltage collapse, and misactuation of relay elements.[27]

Requirement R3 Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or Transmission Owner under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

Requirement R3 Part 3.3 provides that the SOL methodology shall ensure that System Voltage Limits are not set at values less than Undervoltage Load Shedding ("UVLS") settings to avoid UVLS operation following N-1 Contingencies. This requirement is designed to be consistent with Order No. 818, which states that UVLS should not be triggered for an N-1 Contingency,

Requirement R3 Part 3.4 ensures that minimum limits are provided. Maximum limits tend to be associated with equipment/facility limitations whereas minimum limits are often used to prevent phenomena associated with minimum voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits," both maximum and minimum, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used. It also

[27] The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

provides the Reliability Coordinator the authority to ensure that Transmission Operators establish System Voltage Limits in a manner that supports System reliability (in the context of system voltage performance).

Part 3.5 requires that the SOL methodology define a method for determining common System Voltage Limits. Entities may independently identify System Voltage Limits, which, if not coordinated, could create reliability issues. For example, one Transmission Operator may choose very wide System Voltage Limits on its equipment while another Transmission Operator may choose much tighter System Voltage Limits even within the same substation. The Transmission Operator with wider System Voltage Limits may operate equipment that are within its System Voltage Limits but cause an exceedance of the other Transmission Operator's equipment limits. Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Requirement R4: The reliability objective of proposed Requirement R4 is to ensure that stability limits are determined according to an established method that meets certain criteria. The currently effective version does not include such a requirement. Requirement R4 provides as follows:

> **R4.** Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:
>
> 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:
>
> 4.1.1. steady-state voltage stability;
> 4.1.2. transient voltage response;
> 4.1.3. angular stability; and
> 4.1.4. System damping.
>
> 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

While the currently effective version of the FAC-011 standard requires that the System demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, it does not provide any specific stability criteria as in proposed Requirement R4, Part 4.1. Requiring specific stability criteria within the SOL methodology improves the standard as it provides greater clarity and uniformity in practices across the industry.

Requirement R4 Part 4.1 also requires that the SOL methodology include descriptions of margins applied. This language provides additional awareness of the Reliability Coordinator practices for offline or on-line calculated stability limits, including any margin used in the application of the stability limits. The Reliability Coordinator has discretion as to the type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 requires that stability limits meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. As discussed below, Requirement R5 sets out the minimum set of Contingencies that entities must use in establishing stability limits.

Requirement R4 Part 4.3 is designed to help clarify how Reliability Coordinators will establish stability limits when the instability impacts multiple Transmission Operators within a Reliability Coordinator Area or adjacent Reliability Coordinator Areas. The SOL methodology could describe the manner in which the Reliability Coordinator establishes the stability limit through its technical analysis, or the method its uses to coordinate and choose between stability limits derived by multiple Transmission Operators.

Requirement R4 Parts 4.4-4.5 require that the SOL methodology provide a description of the key parameters or elements that must be considered and monitored when determining stability limits. These requirement parts would help ensure that the SOL methodology provides enough information to allow entities to consistently use the same method for determining stability limits. For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e., winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow Transmission Operators and other entities to consistently duplicate results from study to study.

Requirement R4 Part 4.4 addresses the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the OPAs and RTAs for which they will be used. As stability limits may vary based on system topology, load, generation dispatch, etc., the stability limits used in OPAs and RTAs should be "valid" or applicable for those system conditions.[28] The description of system conditions for the applicable stability limits required by Part 4.4 allows the use of these limits in OPAs and RTAs for the defined system conditions.

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[28] The definitions for OPA and RTA include "[a]n evaluation of… system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for… operations,"

Requirement R4 Part 4.5 combines Parts 3.1 and 3.4 in the currently effective version of FAC-011 into a single requirement part. It provides Reliability Coordinators flexibility to reflect the varying needs for different types of stability limits within its footprint (e.g., local single unit stability up to wide area or inter area instability). By recognizing that certain types of localized stability issues may not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, the proposed revision recognizes the ability to monitor these localized areas with real-time stability analysis tools.

Requirement R4 Parts 4.6 and 4.7 address how the SOL methodology accounts for Remedial Action Schemes ("RAS"), UFLS, and UVLS. Part 4.6 requires that the SOL methodology describe allowed uses of RAS and other automatic post-Contingency mitigation actions in establishing stability limits. In contrast, Part 4.7 expressly prohibits the consideration of UFLS or UVLS Programs as an acceptable post-Contingency mitigation action. This prohibition preserves the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation," consistent with FERC Order No. 763.[29]

Requirement R5: Proposed Requirement R5 addresses the Contingency events for use in determining stability limits and performing OPAs and RTAs, combining the requirements for single Contingencies (formerly FAC-011-3, Requirement R2, Part 2.2) and for multiple Contingencies (formerly of FAC-011-3, Requirement R3 Part 3.3). Proposed Requirement R5 provides:

> **R5.** Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

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[29] As described within PRC-006-2 in alignment with FERC Order No. 763, UFLS programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures."

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Requirement R5 Part 5.1 identifies the minimum set of single Contingencies that entities must use in establishing stability limits and performing OPAs and RTAs. As in the current version of the standard (FAC-011-3, Requirement R2 Part 2.2 and Requirement R3 Part 3.3), proposed Requirement R5 Part 5.2 provides the Reliability Coordinator the flexibility to determine which additional single and multiple Contingencies to respect given the unique characteristics of its system. For instance, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the risk related to such an event is relevant in the Reliability Coordinator Area.

Requirement R5 Part 5.3 provides a link between planning and operations by ensuring that the Reliability Coordinator's SOL methodology describes the manner in which the Contingency event information the Planning Coordinator provides under FAC-014-3, Requirement R7 is used in deriving stability limits for operations.

Requirement R6: Proposed Requirement R6 establishes the performance framework for determining SOL exceedances when performing OPAs, RTAs, and Real-time monitoring. The proposed performance framework would enhance consistency across the industry in determining what constitutes an SOL exceedance during operations. The proposed performance framework is designed to align with the SOL construct in the TOP/IRO standards and reflect the concepts in the Whitepaper on System Operating Limit Definition and Exceedance Clarification ("SOL Whitepaper"), included as Exhibit E hereto.

Proposed Requirement R6 provides:

> **R6.** Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:
>
> 6.1. System performance for no Contingencies demonstrates the following:
>
> 6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.
>
> 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.
>
> 6.1.3. Predetermined stability limits are not exceeded.
>
> 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.
>
> 6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:
>
> 6.2.1. Steady state post-Contingency flow through Facilities are within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.
>
> 6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

> 6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.
>
> 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.
>
> 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.
>
> 6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made. [footnotes omitted]

An SOL exceedance would occur if, in the assessment of pre- and post-Contingency conditions, this performance framework is not met. In Real-time operations, SOL exceedances are determined through Real-time monitoring and RTAs, while in the day-ahead, potential SOL exceedances are determined through OPAs. For Facility Ratings and System Voltage Limits, SOL exceedances are identified through the evaluation of the pre-Contingency state and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

Requirement R6 Part 6.1 sets out the framework for System performance for no contingencies and Part 6.2 sets out the framework for System performance for the single contingencies listed in Part 5.1. For each of these scenarios, Parts 6.1-6.2 prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual or expected flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits. The following is a discussion of how these requirement parts would apply to each type of SOL.

Facility Rating Exceedance: As discussed in the SOL Whitepaper, Facility Ratings include Normal Ratings and one or more Emergency Ratings. Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life. Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or RTAs. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet the performance framework articulated in Requirement R6 Part 6.1.1. The use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition.[30]

Requirement R6 Part 6.2.1 provides "Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating" to address the scenario where the System Operator has insufficient time to implement post-Contingency mitigation actions (i.e., actions taken after the Contingency event occurs). The language in Part 6.2.1 provides that exceeding the highest Emergency Rating will be identified as an SOL exceedance, resulting in the Transmission Operator taking pre-Contingency mitigation actions consistent with the Operating Plan as soon as possible to address the condition.

System Voltage Limit Exceedance: System performance for System Voltage Limits is determined through OPAs and RTAs. Normal and emergency maximum and minimum System Voltage Limits are required to be established by the Transmission Operator in accordance with the

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[30] The SOL Whitepaper provides additional detail on the performance framework for Facility Ratings and illustrates how the framework would apply to different scenarios.

Reliability Coordinator's SOL methodology. Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are typically applicable for the post-Contingency state. As provided in Requirement R6 Part 6.1.2 and 6.2.2, System Voltage Limits are exceeded when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when an RTA indicates that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event.

Stability Limit Exceedance: Transient and voltage stability limits can be determined through prior studies, or they can be determined in Real-time. Transient stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism. Though voltage stability limits can be determined, expressed, and monitored in several ways, the general principle is universal: voltage stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency from resulting in instability. Requirement R6 Parts 6.1.3 and 6.2.3 articulate this concept. Part 6.1.3 provides that when there is no Contingency, acceptable System performance occurs when operation is within all pre-determined stability limits. Part 6.2.3 provides that acceptable System performance for the single contingencies listed in Requirement

R5 occurs when all stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.

Requirement R6 Parts 6.1.4, 6.2.3, and 6.2.4 include a footnote that states, "Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques." This footnote acknowledges that there are multiple methods to assessing whether System performance demonstrates Instability, Cascading, or uncontrolled separation that adversely impact the reliability of the BES. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA, and Real-time monitoring. Other entities use tools that run at the time of the OPA or RTA to assess acceptable performance or determine stability limits. Others use other offline analysis techniques.

Requirement R6 Part 6.3 addresses System performance for the multiple contingencies the Reliability Coordinators identify under Requirement R5 that are more severe than the single Contingency events. Per Part 6.3, if any of the more severe Contingency events were to occur, the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation.

Requirement R6 Part 6.4 retains the requirement in currently effective FAC-011-3 Requirement R2, Part 2.3.2 and articulated in Order No. 705 that System Operators may only use load shedding as a measure of last resort to prevent cascading failures. Part 6.4 provides that Operating Plans may only provide for load shedding after other available system adjustments have been made. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan.

Requirement R7: The reliability objective of proposed Requirement R7 is to ensure that SOL exceedances are communicated to the relevant entities in a timely manner. Proposed Requirement R7 provides:

> **R7.** Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include:
>
> 7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.
>
> 7.1.1 IROL exceedances;
>
> 7.1.2 SOL exceedances of stability limits;
>
> 7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;
>
> 7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and
>
> 7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.
>
> 7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.
>
> 7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and
>
> 7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

The risk-based approach in proposed Requirement R7 is designed to require entities to communicate only those SOL exceedances deemed material to reliable operations. The SDT concluded that it would be overly burdensome and unnecessary for Transmission Operators to communicate every SOL exceedance identified in an RTA or during Real-time monitoring as many of those will be of a short duration (e.g., less than 15 min) and routinely resolved by the Transmission Operator or market signals. Proposed Requirement R7 therefore provides the

Reliability Coordinator the authority to develop a risk-based approach for communicating SOL exceedances. Part 7.1, however, establishes the minimum set of SOL exceedances that must always be communicated, regardless of duration, given their likelihood to have a material impact on operations. The Reliability Coordinator has discretion to set the timeline for such communication.

Additionally, Requirement R7 Part 7.2 lists those types of SOL exceedances that must be communicated if not resolved within 30 minutes. The SDT concluded that while the subset of SOL exceedances listed in Part 7.2 presented a lower risk than those listed in Part 7.1, they should always be communicated as their risk profile increases if they persist for a longer duration. The Reliability Coordinator's methodology must specify the timeframe within which these types of SOL exceedances must be communicated.

As discussed further below, NERC is proposing modifications to TOP-001-5, Requirement R15, and IRO-008-3, Requirements R5 and R6 to provide that communication of SOL exceedance should occur "in accordance with its Reliability Coordinator's SOL methodology."

Requirement R8: Proposed Requirement R8 addresses the method for determining IROLs. As noted above, IROL issues were separated from the scope of Project 2015-09 for further technical consideration. Accordingly, proposed Requirement R8 uses language from the currently effective version of the standard. Proposed Requirement R8 provides:

> **R8**. Each Reliability Coordinator shall include in its SOL methodology:
>
> 8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).
>
> 8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL Tv.

Proposed Part 8.1 maps to Requirement R1, Part 1.3 of the currently effective version of the standard. Proposed Part 8.2 maps to Requirement R3, Part 3.7 of the currently effective version of the standard, although it replaces the word "violated" with "exceeding" to align the language with the rest of the standard and the TOP/IRO standards.

Requirement R9: Proposed Requirement R9 addresses the communication of the SOL methodology to those that are responsible for establishing SOLs and those that have a reliability need to know the manner in which SOLs are developed in that Reliability Coordinator Area. Proposed Requirement R9 provides:

> **R9.** Each Reliability Coordinator shall provide its SOL methodology to:
>
> 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.
>
> 9.2. Each of the following entities prior to the effective date of the SOL methodology:
>
> 9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;
>
> 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;
>
> 9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and
>
> 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Proposed Requirement R9 maps to Requirement R4 of FAC-011-3 but references the Planning Coordinator, not Planning Authority, to be consistent with the Functional Model and the TPL-001 standard. Requirement R9, Part 9.2.2 also uses the phrase "responsible for planning" instead of "models any portion of" to better distinguish those Planning Coordinators and Transmission Planners who have a reliability-related need for the methodology from those who simply acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area.

NERC is also proposing to retire the WECC Regional Difference currently in the FAC-011 standard. When the FAC-010 and FAC-011 standards were originally created in 2007, WECC had regional planning criteria in place, which was a combination of NERC Planning Standards and additional WECC Reliability Criteria. WECC added Regional Differences to these standards to include the additional planning criteria that were in effect at that time. The WECC Regional Difference essentially requires the evaluation of specified multiple Facility Contingencies when establishing SOLs. With the adoption of TPL-001-4, which resulted in significant changes to planning requirements, the WECC Regional Differences in FAC-010 and FAC-011 became redundant. WECC therefore proposed the elimination of the Regional Differences in the FAC-010 and FAC-011 standards.[31]

Additionally, the modifications in proposed FAC-011-4 further obviate the need for the WECC Regional Difference. As discussed above, FAC-011-4 Requirement R5 provides Reliability Coordinators the responsibility to determine which, if any, multiple contingencies should be included in the determination of stability limits in OPAs and RTAs. The list in the Regional Difference is simply outdated and there is no reliability need for the Regional Difference to require specific multiple contingencies beyond those specified by the Reliability Coordinator.

6. Proposed Reliability Standard FAC-014-3

The purpose of proposed FAC-014-3 is to "ensure that [SOLs] used in the reliable operation of the [BES] are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies." Proposed FAC-014-3 improves upon the prior version of the standard by (1) clarifying functional entity responsibilities for establishing and communicating each type of SOL, and (2) enhancing

[31] Additional information on the elimination of the WECC Regional Difference, including the rationale and process for WECC's proposal, is available here: https://www.wecc.org/Standards/Pages/WECC-0113.aspx.

coordination between planning and operations. The following is a description of each of the eight requirements of proposed FAC-014-3:

Requirements R1-R2 and R4 set out which functional entity is responsible for establishing SOLs and IROLs. Consistent with the currently effective version of the standard, Reliability Coordinators are responsible for establishing IROLs for its Reliability Coordinator Area (Requirement R1) and Transmission Operators are responsible for establishing SOLs for their portion of the Reliability Coordinator Area (Requirement R2), except that Reliability Coordinators are responsible for establishing stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area (Requirement R4).

As discussed in the SDT's Technical Rationale and mapping document for proposed FAC-014-3 (Exhibits C-2 and D-3, respectively), these requirements improve upon the currently effective version of the standard by: (1) removing ambiguous language that could be misread to make Reliability Coordinators responsible for ensuring the Transmission Operators established SOLs such that a failure of the Transmission Operator to establish SOLs in accordance with the SOL methodology could also result in a violation of FAC-014 for the Reliability Coordinator, and (2) removing ambiguous language from Requirement R2 that could be misinterpreted to require Transmission Operators to establish SOLs only if they have been specifically directed to by their Reliability Coordinator. The proposed language makes clear that each Transmission Operator is responsible for establishing SOLs for its portion of the Reliability Coordinator Area in accordance with the Reliability Coordinator's SOL methodology.

Proposed Requirement R4 also improves upon the currently effective version by requiring Reliability Coordinators to establish stability limits when the limit impacts more than one

Transmission Operator in its footprint or adjacent footprints. This requirement ensures that the Reliability Coordinator, who has wide-area responsibility, establishes such stability limits and prevent any gaps in identification and monitoring of such stability limits. Transmission Operators are still required to establish stability limits for its system (including Generator Operator areas interconnected to its system) but Reliability Coordinators are now responsible for establishing a stability limit that impacts more than one Transmission Operator regardless of whether that stability limit was originally calculated by the Reliability Coordinator or one of the impacted Transmission Operators.

Where a stability limit impacts an adjacent Reliability Coordinator, the Reliability Coordinator establishing the stability limit shall use its own methodology and communicate the limit to the adjacent Reliability Coordinator(s) or Transmission Operators in accordance with other requirements: IRO-008-2, Requirement R5, IRO-014-3, Requirements R1.4 and R1.5, and proposed FAC-014-3, Requirement R5.3, as applicable. If different limits are established by each of the adjacent Reliability Coordinators or multiple Transmission Operators, the more conservative of the two limits should be the one used in operations in accordance with IRO-009-2, Requirement R3 or TOP-001-4, Requirement R18, respectively.

Proposed Requirements R3 and R5 address the communication of established SOLs. First, under Requirement R3, Transmission Operators must provide their SOLs to their Reliability Coordinators. The Transmission Operator should refer to the Reliability Coordinator's documented data specification necessary for performing OPAs, Real-time monitoring, and RTAs under IRO-010-2 for any guidance or requirements regarding the communication of SOLs.

Under Requirement R5, the Reliability Coordinator is then responsible for providing the SOLs (including the subset that are IROLs) to Planning Coordinators, Transmission Planners, and other Transmission Operators, as follows. At least once every 12 calendar months, the Reliability Coordinator must provide each Planning Coordinator and Transmission Planner within its Reliability Coordinator Area: (1) the SOLs for its Reliability Coordinator Area (Part 5.1), and (2) the following information for each established stability limit and IROL: the value of the stability limit or IROL, the Facilities that are critical to the derivation of the stability limit or the IROL, the associated IROL Tv for any IROL, the associated critical Contingency(ies), a description of system conditions associated with the stability limit or IROL, and the type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability) (Part 5.2). The objective of these requirement parts is to provide the planning entities the relevant information necessary for performing their annual assessments.

Additionally, in an agreed upon timeframe, the Reliability Coordinator must provide each impacted Transmission Operator within its Reliability Coordinator Area: (1) the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1 for inclusion in the Transmission Operator's OPAs, Real-time monitoring, and RTAs (Part 5.3), and (2) the information identified in Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information (Part 5.4). The additional information covered under Requirement R5 Part 5.4 helps ensure that the Transmission Operator has the necessary information for performing OPAs and RTAs.

The Reliability Coordinator must also provide each requesting Transmission Operator within its Reliability Coordinator Area SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule (Requirement R5 Part 5.5). A Transmission Operator may want such information, for example, for deriving a new SOL that may impact adjacent Transmission Operators.

Last, consistent with FERC's directive in Order No. 777, the Reliability Coordinator must provide each impacted Generator Owner or Transmission Owner within its Reliability Coordinator Area with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies, at least once every twelve calendar months (Requirement R5 Part 5.6). As discussed above, this information would help asset owners understand which of their facilities are critical to maintaining reliability and require increased protection under the CIP standards.

The proposed Requirement R5 addresses both the content and the frequency at which the information is provided. It also complements existing requirements that provide for communication of SOLs and SOL-related information (e.g., TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. Transmission Operator-to-Transmission Operator communication is addressed in TOP-003-3 and Reliability Coordinator-to-Reliability Coordinator communication is addressed in IRO-014-2.

Proposed Requirements R6-R8 further address coordination between planning and operations. Requirement R6 is designed to align the Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models. Analysis of these models determine System needs, potential future transmission expansion, and other CAPs for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 aligns the analysis input assumptions and System performance criteria used in planning and operating the BES by requiring each Planning Coordinator and Transmission Planner to "implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning

Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology."

Requirement R6 thus provides a mechanism for the coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria in planning models to those established in accordance with the Reliability Coordinator's SOL methodology. As the analysis of planning models determines which Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the Reliability Coordinator's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The SDT recognized, however, that there are instances where it may be appropriate for planning models to have less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in accordance with the SOL methodology. For example, the planning entities may need to model for an upgrade to its system that increases the Facility Rating (typically, the thermal limit) of the equipment in question. So long as the operators are aware of this exception, planning and operations will continue to be aligned. Accordingly, proposed Requirement R6 provides that the Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits, and stability criteria, if it provides a technical rationale to each affected Transmission Planner, Transmission Operator, and Reliability Coordinator. Similarly, the Transmission Planner may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator, and Reliability Coordinator.

Proposed Requirement R7 also enhances coordination between planning and operations by requiring Planning Coordinators and Transmission Planners to communicate the following information to each impacted Transmission Operator and Reliability Coordinator annually:

- The CAP developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as RAS, UVLS, or any Operating Procedures) (Part 7.1).
- The type of instability addressed by the CAP (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping) (7.2).
- The associated stability criteria violation requiring the CAP (e.g. violation of transient voltage response criteria or damping rate criteria) (7.3).
- The planning event Contingency(ies) associated with the identified instability requiring the CAP (7.3).
- The System conditions and Facilities associated with the identified instability requiring the CAP (7.5).[32]

Providing this information would help inform Reliability Coordinators and Transmission Operators when establishing SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure or RAS. If the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be

[32] Requirement R7 references CAPs, in part, to clarify that the requirement does not include the communication of information related to Extreme Events. The SDT concluded that including Extreme Events would dilute the information provided under this requirement and may be an undue burden to planning entities. The use of CAPs also eliminates requirements to provide information on simple out of step generator protection (properly) taking a unit offline.

unaware of these risks and the measures required to address them. Currently effective FAC-014-2, Requirement R6 requires the sharing of similar, though less detailed, information.

Proposed Requirement R8 requires Planning Coordinators and Transmission Planners to, on an annual basis, provide each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near- Term Transmission Planning Horizon. This requirement helps ensure that Transmission Owners and Generation Owners have the appropriate details regarding potential instability, Cascading, or uncontrolled separation identified in their Planning Assessment for the Near-Term Transmission Planning Horizon. The owners can then use this information to identify the Facilities that, as required by other Reliability Standards (e.g., CIP-002, CIP-014, FAC-003), require some level of protection, hardening, or increased vegetation management. This requirement addresses the FERC Order No. 777 directive to address the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement R5 Part 5.6, provides annual notifications to Facility owners from both operating and planning entities.

7. Proposed Reliability Standard IRO-008-3

As noted above, NERC is proposing changes to the IRO-008 standard to align it with the proposed changes in FAC-011-4. The IRO-008 standard requires Reliability Coordinators to perform analyses and assessments (e.g., OPA) to prevent instability, uncontrolled separation, or Cascading. The most substantial revision was the addition of new Requirement R7. Proposed Requirement R7 provides the link to proposed FAC-011-4, Requirement R6 by requiring a Reliability Coordinator to use its SOL methodology when determining SOL exceedances for

RTAs, Real-time monitoring, and OPAs. NERC is also proposing modifications to Requirements R5 and R6 to require the notifications regarding SOL or IROL exceedances to be done according to the risk-based approach in the Reliability Coordinator's SOL methodology required in proposed FAC-011-4, Requirement R7.

8. Proposed Reliability Standard TOP-001-6

Similarly, NERC is proposing changes to the TOP-001 standard to align it with proposed FAC-011-4. The TOP-001 standard includes requirements related to Transmission Operators' obligations to conduct Real-time monitoring and RTAs, among other things. The most substantial revision was the addition of new Requirement R25. Proposed Requirement R25 provides the link to proposed FAC-011-4, Requirement R6 by requiring Transmission Operators to use its Reliability Coordinator's SOL methodology when determining SOL exceedances for RTAs, Real-time monitoring, and OPAs. NERC is also proposing modifications to Requirement R15 to require notifications regarding SOL exceedances to be done according to the risk-based approach in the Reliability Coordinator's SOL methodology required in proposed FAC-011-4, Requirement R7.

V. EFFECTIVE DATE

The implementation plan is attached to this filing as **Exhibit B**. The proposed implementation plan provides that, where approval by an applicable governmental authority is required, the proposed Reliability Standards, NERC Glossary terms, and retirements would become effective on the first day of the first calendar quarter that is 24 months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority. Where approval by an applicable governmental authority is not required, the proposed Reliability Standards, NERC Glossary terms, and retirements would become effective on the first day of the first calendar quarter that is 24 calendar months after the date the standards and terms are adopted by the NERC

Board of Trustees, or as otherwise provided for in that jurisdiction. The currently effective versions of the standards would be retired immediately prior to the effective date of the revised Reliability Standards. This implementation timeline reflects consideration that entities will need to establish and develop new procedures and processes to meet the proposed requirements. Many entities may also need to make certain enhancements to systems, such as their energy management systems or Real-time Contingency Analysis tools, to help them comply with the new requirements, particularly those related to identifying SOL exceedances.

The implementation plan also specifies that unless otherwise specified therein, the elements of the implementation plans for FAC-003-4, PRC- 002- 2, PRC- 023- 4, and PRC- 026- 1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC- 002- 3, PRC- 023- 5, and PRC- 026- 2. This provision helps ensure that certain timelines in those prior implementation plans remain unchanged. The implementation plan also includes additional implementation provisions to address revisions in proposed Reliability Standards PRC-002-3, PRC-023-5, PRC- 026- 2, and FAC-014-3 that require new or different actions by the same or different entities than the prior version of the Reliability Standards required. These additional provisions largely address when entities must comply with periodic requirements after the effective date of the modified version of the standard.

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Respectfully submitted,

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EXHIBITS A, B, C, D, E, G, and I

EXHIBIT H

EXHBIIT F

Reliability Standards Criteria

The discussion below explains how the proposed Reliability Standards and modifications to the Glossary of Terms Used in NERC Reliability Standards have met or exceeded the Reliability Standards criteria.

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

The proposed Reliability Standards (FAC-011-4, FAC-014-3, FAC-003-5, IRO-008-3, PRC-002-3, PRC-023-5, PRC-026-2, and TOP-001-6) would advance the reliability of the Bulk-Power System ("BPS") by clarifying the framework for establishing and communicating System Operating Limits ("SOLs") used in operations. The use of SOLs is a foundational construct in NERC's Reliability Standards for providing for the reliable operation of the BPS. SOLs are the Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in operations for monitoring and assessing pre- and post-Contingency operating states. Under the NERC Reliability Standards, SOLs serve as the parameters within which the BES should be operated to provide for reliable pre- and post-contingency System performance.

The proposed standards would also enhance coordination between planning and operations as it relates to analysis input assumptions and System performance criteria.

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

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply. The requirements clearly state which functional entities are subject to the requirements. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

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

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and FERC guidelines related to their assignment, as discussed further in Exhibit G. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences.

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

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

The proposed Reliability Standards achieve their reliability goals effectively and efficiently. The proposed Reliability Standards would achieve the reliability goal of improving the manner in which Reliability Coordinators and Transmission Operators establish and communicate SOLs and SOL-related information.

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

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. The proposed Reliability Standards would enhance reliability by clarifying the roles and responsibilities for establishing and communicating SOLs.

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

The proposed Reliability Standards would continue to apply consistently throughout North America and do not favor one geographic area or regional model. The proposed Reliability Standards would provide sufficient flexibility to accommodate regional/geographic differences.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.

The proposed Reliability Standards would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standards would require the same performance by each of the applicable entities.

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

The proposed effective date for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan is Exhibit B to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Reliability Standard development process.

The proposed Reliability Standards were developed in accordance with NERC's ANSI-accredited processes for developing and approving Reliability Standards. Exhibit H includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.

NERC has identified no competing public interests regarding the request for approval of these proposed Reliability Standards. No comments were received that indicated that one or more of the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.

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