June 30, 2008

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation,*
Docket No. RM07-3-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in accordance with Order No. 705,[1] as well as Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Commission's regulations, seeking approval for three Reliability Standards: FAC-010-2 — System Operating Limits Methodology for the Planning Horizon, FAC-011-2 — System Operating Limits Methodology for the Operations Horizon and FAC-014-2 — Establish and Communicate System Operating Limits that are contained in Exhibit A to this petition. These proposed Reliability Standards are submitted in response to the Commission directives in Order No. 705, in which the Commission approved the initial version of these Reliability Standards.

These proposed standards were approved by the NERC Board of Trustees. NERC requests that FAC-010-2 be made effective on July 1, 2008, FAC-011-2 on October 1,

[1] *Facilities Design, Connections and Maintenance Reliability Standards,* 121 FERC ¶ 61,296 (2007) ("Order No. 705").

2008, and FAC-014-2 on January 1, 2009, consistent with the implementation dates of Version 1 of these Reliability Standards.

NERC's petition consists the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed reliability standards meet the Commission's requirements;
- Reliability Standards FAC-010-2, FAC-011-2 and FAC-014-2 submitted for approval (**Exhibit A**);
- Rationale for Assignment of Violation Severity Levels (**Exhibit B**);
- Standard Drafting Team Roster (**Exhibit C**); and
- The complete development record of the proposed Reliability Standards (**Exhibit D**).
- Federal Register Notice (**Exhibit E**)

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael
Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM07-3-000** **)**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF FAC-010-2, FAC-011-2 and FAC-014-2 RELIABILITY STANDARDS

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June 30, 2008

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[2] hereby requests the Federal Energy Regulatory Commission (the "Commission" or "FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[3] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5, three NERC Reliability Standards, FAC-010-2 — System Operating Limits Methodology for the Planning Horizon, FAC-011-2 — System Operating Limits Methodology for the Operations Horizon and FAC-014-2 — Establish and Communicate System Operating Limits. These proposed Reliability Standards supersede Version 1 of these Reliability Standards and were developed pursuant to the Commission directives in Order No. 705,[4] in which the Commission approved Version 1 of these proposed Reliability Standards.

On June 27, 2008, the NERC Board of Trustees approved the three proposed Reliability Standards that are the subject of this petition. NERC requests that the Commission approve the FAC-010-2, FAC-011-2 and FAC-014-2 Reliability Standards and make them effective in accordance with the implementation plan included with the proposed Reliability Standards pursuant to the Commission's procedures.

Exhibit A to this filing sets forth the proposed Reliability Standards. **Exhibit B** provides the rationale for the assignment of Violation Severity Levels to the proposed Reliability Standards. **Exhibit C** contains the members of the standard drafting team roster that developed the proposed Reliability Standards. **Exhibit D** contains the

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[2] NERC has been certified by the Commission as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").
[3] 16 U.S.C. 824o.
[4] *Facilities Design, Connections and Maintenance Reliability Standards,* 121 FERC ¶ 61,296 (2007) ("Order No. 705").

complete development record of the proposed Reliability Standards. **Exhibit E** provides a notice for the Federal Register.

NERC also is filing these proposed Reliability Standards with governmental authorities in Canadian provinces and with the National Energy Board of Canada.

II. NOTICES AND COMMUNICATIONS

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

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*Persons to be included on the Commission's service list are indicated with an asterisk.

III. BACKGROUND

The Reliability Standards proposed for approval are revised versions of existing Commission-approved Reliability Standards that directly address matters identified by the Commission in Order No. 705. Because the proposed Reliability Standards were developed in response to Commission Order No. 705, they were not included in NERC's standards development work plan as developed in the Fall of 2007.

IV. JUSTIFICATION FOR APPROVAL OF THE PROPOSED RELIABILITY STANDARDS

The Commission approved Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1 in Order No. 705[5] on December 27, 2007. The Commission found that Version 1 of these Reliability Standards were just, reasonable, not unduly discriminatory or preferential and in the public interest. However, the Commission directed NERC, *inter alia*, to address certain issues as follows:

- The Commission indicated disagreement[6] with NERC's application of the phrase "load greater than studied" in Requirement R2.3.2 in FAC-011-1.
- The Commission remanded the term "Cascading Outages" and stated that NERC could refile a revised definition to addresses the Commission's concerns[7].
- The Commission directed NERC to file Violation Severity Levels[8] for each Reliability Standard to replace "Levels of Non-Compliance" by the time the Reliability Standards become effective: July 1, 2008 for FAC-010-1; October 1, 2008 for FAC-011-1; and January 1, 2009 for FAC-014-1.

[5] *Id.* at P 1.
[6] *Id.* at P 70.
[7] *Id.* at P 111.
[8] *Id.* at P 137.

- The Commission directed NERC to clarify the use of the term "loss of consequential load"[9] in Requirement R2.3 in FAC-010-1 and FAC-011-1.

In this filing, NERC has addressed each of these issues in the proposed Reliability Standards. The basis upon which the Commission approved Version 1 applies to the Version 2 Reliability Standards contained herein.

NERC used the Commission-approved *Reliability Standards Development Procedure*, Version 6.1 to make the following revisions to FAC-010-1, FAC-011-1 and FAC-014-1 to meet the directives in paragraphs 53, 70, 111 and 137 of Order No. 705 as follows:

- FAC-011-1 was revised to remove the phrase, "load greater than studied" from Requirement R2.3.2. As the phrase serves as an example, its removal does not materially change the requirement or the reliability standard.
- The NERC Board of Trustees withdrew its approval of the term "Cascading Outage" at its February 12, 2008 meeting. The drafting team reviewed the term "Cascading Outage" relative to the term "Cascading," a term in the approved NERC Glossary of Terms and indicated there were no intended material differences in the terms. As a result, the term "Cascading Outage" was removed from proposed FAC-010-2 and FAC-011-2 Reliability Standards and replaced with the term "Cascading."
- Regarding the term "loss of consequential load," NERC believes that revisions to this term is best addressed in the modifications being made to the transmission planning ("TPL") family of standards in Project 2006-02 Assess

[9] *Id.* at P 53.

Transmission Future Needs and Develop Transmission Plans. As NERC stated in its response to the Notice of Proposed Rulemaking on FAC-010-1, FAC-011-1 and FAC-014-1, the TPL standards that define acceptable system performance response serve as the foundation for the FAC family of standards. The term "loss of consequential load" is intrinsic to the scope of Project 2006-02; the drafting team has already proposed a definition for the term to be presented for approval for inclusion in NERC's Glossary of Terms. This proposed approach will provide the clarity needed for this term.

- NERC developed a full suite of Violation Severity Levels for FAC-010-2, FAC-011-2 and FAC-014-2. The rationale for development of the Violation Severity Level assignments for the proposed Reliability Standards is included in **Exhibit B**. Subsequently, on June 19, 2008, the Commission issued its "Order on Violation Severity Levels Proposed by the Electric Reliability Organization" in Docket No. RR08-4-000.[10] In the June 19 Order, the Commission announced four new guidelines to be used to determine the validity of Violation Severity Level assignments.[11] However, the Commission noted that these guidelines were not intended to replace NERC's seven classifications or related criteria, rather they just provide an additional level of analysis.[12] NERC respectfully requests that the Commission approve the Violation Severity Levels contained in this filing. NERC commits to assess the Violation Severity Levels using the four new guidelines in the six month compliance filing required by the June 19 Order.

[10] *North American Electric Reliability Corporation*, 123 FERC ¶ 61,284 (2008) ("June 19 Order").
[11] *Id.* at P 17.
[12] *Id.* at P 18.

V. <u>SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS</u>

On December 27, 2007, the Commission issued Order No. 705 approving FAC-010-1, FAC-011-1 and FAC-014-1 Reliability Standards to become mandatory and enforceable in the United States. In the Order, FERC also directed NERC to make the following modifications using the Reliability Standards Development Process:

- FAC-010-1 Requirement R2.3 — clarify what is meant by the term, "loss of consequential load"
- FAC-011-1 Requirement R2.3 — clarify what is meant by the term, "loss of consequential load"
- FAC-011-1 Requirement R2.3.2 — eliminate the phrase, "load greater than studied"

In addition, FERC:

- Remanded the definition of "Cascading Outage" to NERC;
- Accepted three new definitions for inclusion in the NERC Glossary;
- Directed that "Levels of Non-Compliance" be replaced with the "Violation Severity Levels" before the FAC standards take effect;
- Directed NERC to modify Violation Risk Factors in accordance with FERC's directives in the Order; and
- Accepted NERC's proposal for modified effective dates for the three standards.

At the February 12, 2008 Board of Trustees meeting, the NERC Board:

- Approved revised Violation Risk Factors as directed in Order No. 705;

- Established new effective dates of July 1, 2008, for FAC-010-1; October 1, 2008, for FAC-011-1; and January 1, 2009, for FAC-014-; and.
- Withdrew its November 1, 2006 approval of the definition of "Cascading Outage" without prejudice to the ongoing work of the FAC standards drafting team and the revised standards that are developed through the standards development process.

On January 11, 2008, the chair of the Facility Ratings standard drafting team submitted a standards authorization request ("SAR") with proposed standards revisions to:

- Address the issue of "loss of consequential load" in FAC-010-1 and FAC-011-1;
- To eliminate the phrase, "load greater than studied" in FAC-011-1;
- Remove the term "cascading outage" in FAC-010-1 and FAC-011-1 and replace with the existing NERC-approved term "cascading"; and
- Propose Violation Severity Levels to replace Levels of Non-Compliance in all three standards.

The SAR and associated standards were posted for industry comment from January 24 through March 7, 2008. There were 22 sets of comments from more than 130 people representing over 50 companies and 9 of the 10 industry segments. The commenters generally supported these activities. However, to the issue concerning "loss of consequential load," the drafting team determined, from the comments, that it would be more appropriate that the drafting team assigned to modify the TPL Reliability Standards address the clarification desired to "loss of consequential load."

The SAR and associated standards were again posted for industry comment from March 31 through April 29, 2008. There were 13 sets of comments from over 60 people representing 45 companies from 8 of the 10 industry segments. The drafting team made only clarifying edits as a result of the feedback and requested the Standards Committee authorize moving the proposed standards to ballot. Most commenters that commented disagreed with the method that the Violation Severity Levels were developed for certain requirements and associated sub-requirements, preferring that each sub-requirements be given equal weight in supporting the overall performance expectation of the main requirement. The drafting team did not agree that each sub-requirement carried equal weight and therefore did not modify the proposed Violation Severity Levels. This topic is discussed in detail in **Exhibit B**.

The Standards Committee authorized moving the proposed standards to ballot on its May 2, 2008 conference call. NERC opened its pre-ballot window for 30 days from May 2 through June 1, 2008.

The initial ballot was held from June 2 through June 11, 2008. The ballot achieved 95.43 percent weighted segment approval rating with 88.83 percent of the ballot pool participating in the event. However, there were seven negative votes associated with comments necessitating a recirculation ballot, in addition to two affirmative votes with comment. With the exception of typographical errors, no other changes to the standards were made by the team in response to the comments. The drafting team considered the comments and responded to the main themes as summarized below:

- Some balloters proposed modifications to the standards that involve modifications outside the drafting team’s control. One balloter proposed modifying several sets of Violation Severity Levels to treat each of the sub-requirements as though they were of equal weight in contributing to the main requirement. The drafting team gave serious consideration to the contribution of each sub-requirement in achieving the objective of the associated requirement – and the team does not believe that all sub-requirements are of equal weight. For example, if the Planning Authority is required to have a methodology for developing system operating limits, and the methodology that is developed is not suitable for use in the planning horizon, then the methodology cannot be used for its intended purpose – and the intent of the requirement has been totally missed. This meets the criteria for a "Severe" Violation Severity Level. If the Violation Severity Levels were modified as proposed by the commenter, missing this sub-requirement would be classified as a "Lower" Violation Severity Level.

- One balloter suggested that the proposed dates in the implementation plan for the Version 2 standards could be confusing as entities would not know with which requirements to comply. The drafting team noted that there will only be one standard in place at a time, and since the requirements in the proposed standards are the same as those in the already approved "Version 1" standards, it should not be difficult to know what performance is required. (The effective dates of the proposed standards are the same as the approved effective dates for Version 1 of these standards. As the requirements have not materially changed, there are no differing performance expectations from Version 1 to Version 2.)

- One balloter proposed changes to improve the readability or to move some of the Violation Severity Levels from one category to another. The drafting team did not make any of these changes as they do not seem warranted based on the high level of approval achieved during the initial ballot.

NERC conducted the recirculation ballot for the proposed standards from June 13 through June 22, 2008. The ballot achieved 95.21 percent weighted segment approval rating with 89.36 percent of the ballot pool participating in the event. Thus, the proposed Reliability Standards achieved the necessary 75 percent of ballot pool participants and the required two-thirds weighted segment vote to demonstrate consensus. The NERC Board approved these proposed Reliability Standards on June 27, 2008 by email ballot.

In summary, NERC processed the modifications to the FAC-010-1, FAC-011-1 and FAC-014-1 reliability standards, including development of Violation Severity Levels, in accordance with the NERC *Reliability Standards Development Procedure, Version 6.1*.

NERC respectfully requests that the Commission approve the Violation Severity Levels contained in this filing. NERC commits to assess the Violation Severity Levels using the four new guidelines in the six month compliance filing required by the June 19 Order.

VI. CONCLUSION

NERC requests that the Commission approve the proposed FAC-010-2, FAC-011-2 and FAC-014-2 Reliability Standards, as set out in **Exhibit A**. NERC requests that FAC-010-2 be made effective on July 1, 2008, FAC-011-2 on October 1, 2008, and FAC-014-2 on January 1, 2009, consistent with the implementation dates of Version 1 of these Reliability Standards. NERC respectfully requests waiver of the Commission's regulations and applicable provisions of Order No. 705 to the extent necessary to permit the filing to become effective on the dates requested herein."

Respectfully submitted,

/s/ Rebecca J. Michael

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 30th day of June, 2008.

/s/ Rebecca J. Michael
Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standards
FAC-010-2, FAC-011-2, and FAC-014-2
Proposed for Approval

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

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[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21 – March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of Standard posted for recirculation ballot review.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period

Requirement	Lower	Moderate	High	Severe
	that was longer than 45 calendar days but less than 60 calendar days.	that was 60 calendar days or longer but less than 75 calendar days.	that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator’s response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	that was 90 calendar days or longer. OR The Reliability Coordinator’s response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–11, 2008.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Exhibit B

Rationale for Assignment of Violation Severity Levels

Violation severity levels categorize noncompliant performance, with up to four levels identified for each requirement. The standard drafting team for the proposed standards used the following criteria when it proposed violation severity levels:

a) "Lower" Violation Severity Level - noncompliant performance that is missing one minor[13] element (or a small percentage) of the required performance – the performance or product measured is missing a minor element – the performance or product measured has significant value as it almost meets the full intent of the requirement.

b) "Moderate" Violation Severity Level - noncompliant performance that is missing at least one significant[14] element (or a moderate percentage) of the required performance – the performance or product measured still has significant value in meeting the intent of the requirement.

c) "High" Violation Severity Level - noncompliant performance that is missing more than one significant[15] element (or a high percentage) of the required performance or is missing a single vital component – the performance or product measured meets at least one significant element of the performance or product, but has limited value in meeting the intent of the requirement.

d) "Severe" Violation Severity Level - noncompliant performance that is missing most or all of the significant[16] elements (or a significant percentage) of the required performance – the performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

Violation Severity Levels for FAC-010-2

FAC-010-2 has five requirements.

Requirement R1 - The first requirement is for the planning authority to have a methodology for use in developing system operating limits ("SOLs") for use in its planning authority area. There are three sub-requirements that identify elements that must be included in the methodology:

1) The methodology must be applicable for use in the planning horizon;
2) The methodology must include a statement that SOLs cannot exceed their associated facility ratings; and
3) The methodology must describe how to identify which SOLs are also Interconnection Reliability Operating Limits ("IROLs").

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[13] The terms "minor" and "significant" are explained in detail in the discussion accompanying each requirement. Therefore, while subjective in and of themselves, the context provided supports how the terms are defined with respect to the Violation Severity Levels assigned.
[14] *Id.*
[15] *Id.*
[16] *Id.*

The three sub-requirements do not contribute equally to the requirement to have a methodology, and the Violation Severity Levels reflect this uneven weighting as follows:

- If the methodology does not include a statement that the SOLs cannot exceed their associated facility ratings, the methodology could still be used, but it would be missing a significant element – missing this sub-requirement is a "Moderate" Violation Severity Level
- If the methodology does not include a description of how to identify which SOLs are IROLs, then the methodology is missing a vital element that makes the resultant methodology serious flawed – missing this sub-requirement is a "High" Violation Severity Level
- If the methodology is not applicable for use in the planning horizon it cannot be used by the planning authority – missing this sub-requirement is a "Severe" Violation Severity Level
- If there is no methodology, then missing this sub-requirement is a "Severe" Violation Severity Level

Requirement R2 – The second requirement is aimed at ensuring the planning authority's SOL methodology includes a requirement that SOLs provide bulk power system performance that meets defined criteria in various states:

1) Pre-contingency;
2) Immediately following a single contingency and during the adjustment period following a single contingency; and
3) Immediately following multiple contingencies, and during the adjustment period immediately following a multiple contingency.

The sub-requirements do not contribute equally to the requirement to address system performance in the SOL methodology, and the Violation Severity Levels reflect this uneven weighting as follows:

- If the methodology is complete with the exception of addressing the pre-contingency state, then the methodology would still be useful since the pre-contingency state rarely occurs and there are other standards that require studies of the pre-contingency state; therefore, this requirement is assigned a "Lower" Violation Severity Level
- If the methodology is complete with the exception of addressing multiple contingences, then the methodology is still useful, but it is missing a serious element and the requirement is assigned a "Moderate" Violation Severity Level
- If the methodology is complete with the exception of addressing single contingencies, then the methodology is seriously flawed as single contingencies are the most frequently occurring type of contingency, and therefore, the requirement is assigned a "High" Violation Severity Level
- If the methodology is missing both the system response to single contingencies and multiple contingencies, then the methodology misses almost the full intent of

the requirement and the requirement is assigned a “Severe” Violation Severity Level

- If the methodology does not address bulk power system performance at all, then this requirement is assigned a “Severe” VSL

Requirement R3 – The third requirement lists some special topics for inclusion in the methodology. The topics include:

1) Size of the study model;
2) Selection of contingencies;
3) Level of model detail for models used to determine SOLs;
4) Allowed uses of special protection systems;
5) Anticipated transmission system configuration, generation dispatch and Load level; and
6) Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

All of these elements are of near equal importance.

- Missing one element is therefore assigned a “Lower” Violation Severity Level
- Missing two elements is assigned a “Moderate” Violation Severity Level
- Missing three elements is assigned “High” Violation Severity Level
- Missing more than three elements is assigned a “Severe” Violation Severity Level

Requirement R4 – The fourth requirement is aimed at ensuring that the entities that need the planning authority’s SOL methodology receive that methodology and any changes to the methodology before the changes become effective. There are three sub-requirements:

1) The methodology must be distributed to other planning authorities;
2) The methodology must be distributed to the reliability coordinators and transmission operators that operate in the planning authority’s area; and
3) The methodology must be distributed to the transmission planners that work in the planning authority’s area.

The intent of the requirement is to distribute the methodology to all required entities on time – with distribution to each of the required entities of equal weight in contributing to the intent of the requirement.

The Violation Severity Levels address whether the planning authority distributed its methodology to all required entities and address the timeliness of the distribution. As the planning authority’s distribution involves fewer entities, and as the distribution becomes tardier, the less the performance meets the intent of the requirement.

The “Lower” Violation Severity Level addresses a variety of possible noncompliant performance:

- The methodology wasn’t sent to one of the required entities;
- The methodology was distributed up to 30 days late; or
- The methodology wasn’t sent to one of the required entities and it was distributed up to 30 days late.

The “Moderate” Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn’t sent to one of the required entities and it was 30 – 60 days late; and
- The methodology wasn’t sent to two of the required entities and it was distributed up to 30 days late.

The “High” Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn’t sent to one of the required entities and it was distributed up to 60 – 90 days late;
- The methodology wasn’t sent to two of the required entities and it was distributed up to 30 – 60 days late; or
- The methodology wasn’t sent to two of the required entities and it was distributed up to 30 days late.

The “Severe” Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn’t sent to more than three of the required entities;
- The methodology wasn’t sent to one of the required entities and it was distributed more than 90 days late;
- The methodology wasn’t sent to two of the required entities and it was distributed up to 60 – 90 days late;
- The methodology wasn’t sent to three of the required entities and it was distributed up to 30 - 60 days late; or
- The methodology wasn’t sent to four of the required entities and it was distributed up to 30 days late.

Requirement R5 – The fifth requirement forces the planning authority to address peers’ technical comments on its SOL methodology. The intent of this requirement is to ensure that the planning authority makes a prompt review of these technical comments and is forced to document any decision made regarding a change to its SOL methodology. The concept is to use peer pressure to motivate an entity to correct any errors in its methodology.

There are three components associated with meeting the intent of the requirement:

1) The planning authority provided a response;
2) The response was provided in a timely manner; and
3) The response indicated whether the methodology will be changed.

The three components do not contribute equally in meeting the intent of the requirement, as reflected in the Violation Severity Levels:

- If the planning authority provided a complete response, but the response was up to 15 days late, then the Violation Severity Level is “Lower.” If there was a technical issue with the methodology, then there is a commitment to change the methodology and the intent of the requirement has been mostly met.
- If the planning authority provided a complete response, but the response was 15 – 30 days late, then the intent of the requirement has been partially met – but the longer the methodology remains inaccurate, the farther off the entity is from meeting the intent of the requirement and the Violation Severity Level is “Moderate.”
- If the planning authority provided a complete response, but the response was 30 – 45 days late, then the intent of the requirement has been partially met – but the longer the methodology remains inaccurate, the farther off the entity is from meeting the intent of the requirement and the Violation Severity Level is “High.”
- If the planning authority provided a response that indicated it was not making a change but provided no reason for the response, then the Violation Severity Level is “High” since there is no assurance that the methodology in use is correct.
- If the planning authority provided a response, but the response was more than 45 days late, then the response is so late that it seriously impacts achievement of the intent of the requirement, and the Violation Severity Level is “Severe.”
- If the planning authority provided a response, but did not indicate whether it would change its methodology, then the planning authority did not meet the intent of the requirement at all, and the Violation Severity Level is “Severe.”

Violation Severity Levels for FAC-011-2

FAC-011-2 has five requirements.

Requirement R1 - The first requirement is for the reliability coordinator to have a methodology for use in developing SOLs for use in its reliability coordinator area. There are three sub-requirements that identify elements that must be included in the methodology:

1) The methodology must be applicable for use in the operations horizon;
2) The methodology must include a statement that SOLs cannot exceed their associated facility ratings; and
3) The methodology must describe how to identify which SOLs are also IROLs.

The three sub-requirements do not contribute equally to the requirement to have a methodology, and the Violation Severity Levels reflect this uneven weighting as follows:

- If the methodology is not applicable for use in the operations horizon it cannot be used by the reliability coordinator – missing this sub-requirement is assigned a “Severe” Violation Severity Level.

- If the methodology does not include a statement that the SOLs cannot exceed their associated facility ratings, the methodology could still be used, but it would be missing a significant element – missing this sub-requirement is assigned a “Moderate” Violation Severity Level.
- If the methodology does not include a description of how to identify which SOLs are IROLs, then the methodology is missing a vital element that makes the resultant methodology serious flawed – missing this sub-requirement is assigned a “High” Violation Severity Level.
- If there is no methodology, then this is assigned a “Severe” Violation Severity Level.

Requirement R2 – The second requirement is aimed at ensuring the reliability coordinator’s SOL methodology includes a requirement that SOLs provide bulk power system performance that meets defined criteria in various states

1) Pre-contingency
2) Immediately following a single contingency and during the adjustment period following a single contingency

The sub-requirements do not contribute equally to the requirement to address system performance in the SOL methodology and the Violation Severity Levels reflect this uneven weighting as follows:

- If the methodology is complete with the exception of addressing the pre-contingency state, then the methodology would still be useful since the pre-contingency state rarely occurs and there are other standards that require studies of the pre-contingency state and therefore the Violation Severity Level assigned is “Lower.”
- If the methodology is missing the system response to single contingencies but does address the system during the adjustment period following the single contingency, then the methodology has only limited value since single contingencies are the most frequently occurring type of contingency, and the Violation Severity Level is assigned to be “High.”
- If the methodology does not address bulk electric system performance in either the pre-contingency state or following a single contingency and its adjustment period, then the assigned Violation Severity Level is “Severe.”

Requirement R3 – The third requirement lists some special topics for inclusion in the methodology. The topics include:

1) Size of the study model;
2) Selection of contingencies;
3) Process for identifying applicable stability-related multiple contingencies;
4) Level of model detail for models used to determine SOLs;
5) Allowed uses of special protection systems;

6) Anticipated transmission system configuration, generation dispatch and Load level; and
7) Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

All of these elements are of near equal importance.

- Missing one element is assigned a "Lower" Violation Severity Level
- Missing two elements is assigned a "Moderate" Violation Severity Level
- Missing three elements is assigned a "High" Violation Severity Level
- Missing more than three elements is assigned a "Severe" Violation Severity Level

Requirement R4 – The fourth requirement is aimed at ensuring that the entities that need the reliability coordinator's SOL methodology receive that methodology and any changes to the methodology before the changes become effective. There are three sub-requirements:

1) The methodology must be distributed to other reliability coordinators;
2) The methodology must be distributed to the planning authorities and transmission planners that model any portion of the reliability coordinator's area; and
3) The methodology must be distributed to the transmission operators that operate in the reliability coordinator' area.

The intent of the requirement is to distribute the methodology to all required entities on time – with distribution to each of the required entities of equal weight in contributing to the intent of the requirement.

The Violation Severity Levels address whether the reliability coordinator distributed its methodology to all required entities and address the timeliness of the distribution. As the reliability coordinator's distribution involves fewer entities, and as the distribution becomes tardier, the less the performance meets the intent of the requirement.

The "Lower" Violation Severity Level addresses a variety of possible noncompliant performance:

- The methodology wasn't sent to one of the required entities;
- The methodology was distributed up to 30 days late, or
- The methodology wasn't sent to one of the required entities and it was distributed up to 30 days late.

The "Moderate" Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn't sent to one of the required entities and it was 30 – 60 days late.
- The methodology wasn't sent to two of the required entities and it was distributed up to 30 days late.

The “High” Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn’t sent to one of the required entities and it was distributed up to 60 – 90 days late.
- The methodology wasn’t sent to two of the required entities and it was distributed up to 30 – 60 days late.
- The methodology wasn’t sent to two of the required entities and it was distributed up to 30 days late.

The “Severe” Violation Severity Level addresses a variety of noncompliant performance:

- The methodology wasn’t sent to more than three of the required entities.
- The methodology wasn’t sent to one of the required entities and it was distributed more than 90 days late.
- The methodology wasn’t sent to two of the required entities and it was distributed up to 60 – 90 days late.
- The methodology wasn’t sent to three of the required entities and it was distributed up to 30 – 60 days late.
- The methodology wasn’t sent to four of the required entities and it was distributed up to 30 days late.

Requirement R5 – The fifth requirement forces the reliability coordinator to address peers’ technical comments on its SOL methodology. The intent of this requirement is to ensure that the reliability coordinator makes a prompt review of these technical comments and is forced to document any decision made regarding a change to its SOL methodology. The concept is to use peer pressure to motivate an entity to correct any errors in its methodology. There are three components associated with meeting the intent of the requirement addressed in the Violation Severity Levels:

1) The reliability coordinator provided a response;
2) The response was provided in a timely manner; and
3) The response indicated whether the methodology was changed.

The three components do not contribute equally in meeting the intent of the requirement, and this is reflected in the Violation Severity Levels:

- If the reliability coordinator provided a complete response, but the response was up to 15 days late, then the assigned Violation Severity Level is “Lower.” If there was a technical issue with the methodology, and there is a commitment to change the methodology then the intent of the requirement has been mostly met.
- If the reliability coordinator provided a complete response, but the response was 15 – 30 days late, then the intent of the requirement has been partially met – but the longer the methodology remains inaccurate, the farther off the entity is from meeting the intent of the requirement and the assigned Violation Severity Level is “Moderate.”
- If the reliability coordinator provided a complete response, but the response was 30 – 45 days late, then the intent of the requirement has been partially met – but the longer the methodology remains inaccurate, the farther off the entity is from

meeting the intent of the requirement and the assigned Violation Severity Level is "High."

- If the reliability coordinator provided a response that indicated it was not making a change, but provided no reason for the response, then the assigned Violation Severity Level is "High" since there is no assurance that the methodology in use is correct.
- If the reliability coordinator provided a response, but the response was more than 45 days late, then the response is so late that it seriously impacts achievement of the objective of the requirement, and the assigned Violation Severity Level is "Severe."
- If the reliability coordinator provided a response, but did not indicate whether it would change its methodology, then the reliability coordinator did not meet the intent of the requirement at all, and the assigned Violation Severity Level is "Severe."

Violation Severity Levels for FAC-014-2

FAC-014-2 has six requirements.

Requirements R1-R4 - The first four requirements are aimed at ensuring that the SOLs that are developed are consistent with the applicable SOL methodology. For each of these requirements the total number of SOLs can be quite large, and is not the same for every entity. The drafting team defaulted to using the percent of SOLs that are inconsistent with the SOL methodology as the criteria for the Violation Severity Levels:

- 25% of the SOLs inconsistent with the methodology is a "Lower" Violation Severity Level
- 25 – 50% of the SOLs inconsistent with the methodology is a "Moderate" Violation Severity Level
- 50-75% of the SOLs inconsistent with the methodology is a "High" Violation Severity Level
- More than 75% of the SOLs inconsistent with the methodology is a "Severe" Violation Severity Level

Requirement R5 - The fifth requirement forces the responsible entity to distribute its SOLs to all of the entities that have requested them, in accordance with schedules.

If the responsible entity is the reliability coordinator, there are additional sub-requirements that detail information the reliability coordinator must provide for each IROL. There are four components to the supporting information, and these components do not contribute equally to meeting the intent of the requirement.

1) Identification of the facility critical to the IROL
2) The value of the IROL and its T_v
3) The associated contingency or contingencies
4) The type of limit

The Violation Severity Levels address the responsible entity's timeliness in distributing the SOLs, whether the responsible entity distributed the SOLs to all requesting entities, and for the reliability coordinator, whether it provided the information associated with each IROL.

The timeliness aspect of the requirement has Violation Severity Levels separated by half-monthly increments as follows:

- Distribution of SOLs up to 15 days late is a "lower" Violation Severity Level.
- Distribution of SOLs from 15 – 30 days late is a "Moderate" Violation Severity Level.
- Distribution from 30 – 45 days late is a "High" Violation Severity Level.
- Distribution more than 45 days late is a "Severe" Violation Severity Level.

The completeness of delivering the SOLs to all requesting entities was addressed by separating the Violation Severity Levels according to the number of deliveries that were not made:

- Failure to deliver the SOLs to one entity is missing a significant element of this requirement and this is assigned a "Moderate" Violation Severity Level.
- Failure to deliver the SOLs to two entities is missing more than one significant element of this requirement and this is assigned a "High" Violation Severity Level.

If the compliance enforcement authority asks for evidence that the SOLs were delivered to all requesting entities, and there is no evidence, then this is already assigned a "Severe" Violation Severity Level for failure to meet the timeliness aspect of this requirement – so there is no separate "Severe" Violation Severity Level for failure to deliver the SOLs to more than two requesting entities.

The reliability coordinator's requirement to distribute additional information for IROLs is addressed by Violation Severity Levels as follows:

- If the reliability coordinator fails to provide the 'type of limit' but provides the other information about an IROL, then the recipient has sufficient information to identify the IROL, but by not providing the type of limit, the recipient is missing a piece of information that could assist in making operating plans, and this is assigned a "Moderate" Violation Severity Level.

- If the reliability coordinator fails to identify the contingencies associated with the VSL, but provides the other information about an IROL, then the recipient knows the value of the limit, but does not necessarily know what contingency will cause the limit to be exceeded, which is assigned a "High" Violation Severity Level.

- If the reliability coordinator does not identification the facility associated with the IROL, or fails to identify the IROLs and its T_v, then the information provided is so lacking that the intent of the requirement has not been met and this is assigned a "Severe" Violation Severity Level.

Requirement R6 – This requirement is aimed at ensuring that the planning authority identifies and provides any stability-related multiple contingencies it has identified to reliability coordinators that monitor the associated facilities so that those reliability coordinators have this information.

There are two sub-requirements and they are not of equal weight in contributing to the intent of the requirement:

1) To provide the list of multiple contingencies and their associated stability-related limits to all reliability coordinators that monitor the associated facilities.
2) To notify the reliability coordinators if there aren't any stability-related multiple contingencies.

The Violation Severity Levels address whether the planning authority identified the list of stability-related multiple contingencies, whether the planning authority provided the list to all of the reliability coordinators that monitor the associated facilities, and address whether planning coordinator notified reliability coordinators if no stability-related multiple contingencies were identified.

- A failure to notify the reliability coordinators that it did not identify any stability-related multiple contingencies would not seriously impact the intent of this requirement and this is assigned a "Lower" Violation Severity Level.

- A failure to provide the list of stability-related multiple contingencies to one of the reliability coordinators that monitors the facilities is a serious omission, and this is assigned a "High" Violation Severity Level.

- A failure to identify the stability-related multiple contingencies is a total failure in meeting the intent of this requirement, and this is assigned a "Severe" Violation Severity Level.

- If the planning authority fails to distribute the list of stability-related multiple contingencies to more than one of the reliability coordinators, then the intent of this requirement is so seriously missed that this is assigned a "Severe" Violation Severity Level.

Exhibit C

Standard Drafting Team Roster

Facility Ratings Standard Drafting Team

Project 2006-09 — FRSDT

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Exhibit D

Record of Development of Proposed Reliability Standards

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Project 2008-04

Modifications to FAC-010-1, FAC-011-1, and FAC-014-1 for FERC Order 705

Registered Ballot Body | Related Files | Reliability Standards Home Page | Drafting Team Rosters

Status

The Facility Ratings Standards Drafting Team posted the results from recirculation ballot. The Board of Trustees will consider adoption of these FAC standards on June 25, 2008.

Purpose / Industry Need

The purpose of revising these standards is a result of:

FERC Order 705, the Commission directed NERC to make the following modifications:

- FAC-011-1 Requirement R2.3.2 — eliminate the phrase, "load greater than studied"
- Replace levels of non-compliance with Violation Security Levels

In addition, the Commission remanded the definition of "Cascading Outage" and this term should be withdrawn from the NERC Glossary of Reliability Terms.

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Facility Ratings Standards Posted for Board of Trustees Adoption on June 25, 2008 FAC-010-2 Clean (54) FAC-011-2 Clean (55) | redline (56) to last posting FAC-014-2 Clean (57)	Implementation Plan Clean (60)			

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FAC-010, FAC-011, FAC-014 Clean (58) | redline (59) to last approved				
Announcement (50) Facility Ratings Standards Posted for 10-day Recirculation Ballot Window FAC-010-2 Clean (46) FAC-011-2 Clean (47) | redline (48) to last posting FAC-014-2 Clean (49)	Implementation Plan Clean (51)	06/13/08 – 06/22/08 (closed) 10-day Recirculation Ballot Window		Announcement (52) Recirculation Ballot Results (53)
Announcement (41) Facility Ratings Standards Posted for 10-day Ballot Window FAC-010-2 Clean (35) | redline (36) to last posting FAC-011-2 Clean (37) | redline (38) to last posting Note that in the version of FAC-011-2 that was posted for pre-ballot review, there was an error in the initial sentence of the Severe Violation Severity Level for Requirement R3 that has now been corrected as follows: The Reliability Coordinator has a methodology for determining SOLs that is missing a description of ~~three~~ four or more of the following: R3.1 through R3.7. FAC-014-2 Clean (39) | redline (40) to last posting	Implementation Plan Clean (42)	06/02/08 – 06/11/08 (closed) 10-day Ballot Window		Announcement (43) Initial Ballot Results (44) Response to Ballot Comments (45)

Announcement (33) Final SAR Version 2 and Facility Ratings Standards Final SAR Version 2 Clean (26) FAC-010-2 Clean (27) | redline (28) to last posting FAC-011-2 Clean (29) | redline (30) to last posting FAC-014-2 Clean (31) | redline (32) to last posting	Implementation Plan Clean (34)			
Announcement (19) Draft SAR Version 2 and Facility Ratings Standards Posted for 30-day Comment Period Draft SAR Version 2 Clean (11) | redline (12) to last posting FAC-010-2 Clean (13)| redline (14) to last posting FAC-011-2 Clean (15) | redline (16) to last posting FAC-014-2 Clean (17) | redline (18) to last posting	Implementation Plan Clean (20) | redline (21) to last posting	03/31/08 - 04/29/08 (closed) Comment Form (22) Comment Questions (23)	Comments (24)	Consideration of Comments (25)
Announcement (6) Draft SAR Version 1 Facility Ratings Standard Posted for 45-day Comment Period	Implementation Plan (7)	01/24/08 - 03/07/08 (closed) Comment Form (8)	Comments (9)	Consideration of Comments (10)

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Draft SAR Version 1 (1) FAC-010-2 Clean (2) | redline (3) to last posting FAC-011-2 Clean (4) | redline (5) to last posting				
To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.				
Documents in the PDF format require use of the Adobe Reader® software. Free Adobe Reader® software allows anyone view and print Adobe Portable Document Format (PDF) files. For more information download the Adobe Reader User Guide.				Get Adobe Reader

All comments should be forwarded to sarcomm@nerc.net.
Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.

Standard Authorization Request Form

Title of Proposed Standard	Modifications to FAC-010-1 and FAC-011-1 for FERC Order 705
Request Date	January 11, 2008

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)
Name Paul Johnson for Facility Ratings SDT	☐	New Standard
Primary Contact Paul Johnson	☒	Revision to existing Standard FAC-010-1 System Operating Limits Methodology for the Planning Horizon FAC-011-1 — System Operating Limits Methodology for the Operations Horizon
Telephone 614-716-6690 Fax	☐	Withdrawal of existing Standard
E-mail pbjohnson@aep.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) The revisions are needed to eliminate the ambiguity identified by FERC in the approved standards and in the definition of Cascading Outage.
Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.) The regulatory approved version of FAC-010-1 will become effective on July 1, 2008 and set of the clarifications should be made before that time.
Brief Description (Provide a paragraph that describes the scope of this standard action.) In FERC Order 705, the Commission directed NERC to make the following modifications: FAC-010-1 Requirement R2.3 — clarify what is meant by the term, “consequential load” FAC-011-1 Requirement R2.3 — clarify what is meant by the term, “consequential load” FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied” In addition, the Commission remanded the definition of “Cascading Outage” and this term

should be withdrawn from the NERC Glossary of Reliability Terms. “Levels of Non-compliance” should be removed and replaced with the “Violation Severity Levels” developed by the VSL Drafting Team, once those VSLs are approved by their Ballot Body. Update the standard to include the VRFs that were approved or modified in accordance with FERC Order 750.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) In FERC Order 705, the Commission directed NERC to make the following modifications: ▪ FAC-010-1 Requirement R2.3 — clarify what is meant by the term, “consequential load” ▪ FAC-011-1 Requirement R2.3 — clarify what is meant by the term, “consequential load” ▪ FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied” In addition, the Commission remanded the definition of “Cascading Outage” and this term should be retired from the NERC Glossary of Terms Used in Reliability Standards, and the standards should be updated to use the defined term, “Cascading”. The “Levels of Non-compliance” should be removed and replaced with the “Violation Severity Levels” developed by the VSL Drafting Team, once those VSLs are approved by their Ballot Body.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Authority	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	The Regional Variances within FAC-010 and FAC-011 need to be updated to include Violation Severity Levels to comply with FERC Order 705.

Project 2008-04 — Revisions to FAC-010 and FAC-011

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR approved by Standards Committee on January 18, 2008.

Proposed Action Plan and Description of Current Draft:

The drafting team is asking the Standards Committee to authorize posting the SAR and associated modified standards for a 45-day comment period from January 23–March 7, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and request authorization to move forward to pre-ballot posting.	March 14, 2008
2. Post for 30-day pre-ballot period.	March 17–April 15, 2008
3. Conduct initial ballot.	April 16–25, 2008
4. Post response to comments on initial ballot.	April 30, 2008
5. Conduct recirculation ballot.	May 1–10, 2008
6. Board adoption.	May 16, 2008
7. Submit to regulatory authorities for approval.	May 15, 2008

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

~~**Cascading Outages:** The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.~~

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Planning Authority
5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.3.3. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.4. Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur.

R2.5. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.5.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

---

[2] The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Violation Severity Levels (To be added once approved by the VSL Ballot Pool)

3. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07

Project 2008-04 — Revisions to FAC-010 and FAC-011

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR approved by Standards Committee on January 18, 2008.

Proposed Action Plan and Description of Current Draft:

The drafting team is asking the Standards Committee to authorize posting the SAR and associated modified standards for a 45-day comment period from January 23–March 7, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and request authorization to move forward to pre-ballot posting.	March 14, 2008
2. Post for 30-day pre-ballot period.	March 17–April 15, 2008
3. Conduct initial ballot.	April 16–25, 2008
4. Post response to comments on initial ballot.	April 30, 2008
5. Conduct recirculation ballot.	May 1–10, 2008
6. Board adoption.	May 16, 2008
7. Submit to regulatory authorities for approval.	May 15, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

~~**Cascading Outages:** The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.~~

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** ~~July 1, 2007~~July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.3.3. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.4. Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

R2.5. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.5.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

[2] The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. **Additional Compliance Information**

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Violation Severity Levels (To be added once approved by the VSL Ballot Pool)

~~**3.Levels of Non-Compliance (Does not apply to the Western Interconnection)**~~

~~**3.1.Level 1:** There shall be a level one non-compliance if either of the following conditions exists:~~

~~**3.1.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~**3.1.2**No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~**3.2.Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.~~

~~**3.3.Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~**3.3.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~**3.3.2**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the six required topics in R3.~~

~~**3.4.Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.~~

3. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

3.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading o~~O~~utages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading o~~O~~utages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1,	Fixed typo. Removed the word “each”	01/11/07

	2006	from the 1st sentence of section D.1.3, Data Retention.	

Project 2008-04 — Revisions to FAC-010 and FAC-011

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR approved by Standards Committee on January 18, 2008.

Proposed Action Plan and Description of Current Draft:

The drafting team is asking the Standards Committee to authorize posting the SAR and associated modified standards for a 45-day comment period from January 23–March 7, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and request authorization to move forward to pre-ballot posting.	March 14, 2008
2. Post for 30-day pre-ballot period.	March 17–April 15, 2008
3. Conduct initial ballot.	April 16–25, 2008
4. Post response to comments on initial ballot.	April 30, 2008
5. Conduct recirculation ballot.	May 1–10, 2008
6. Board adoption.	May 16, 2008
7. Submit to regulatory authorities for approval.	May 15, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

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[2] The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Violation Severity Levels (To be added once approved by the VSL Ballot Pool)

3. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New

Project 2008-04 — Revisions to FAC-010 and FAC-011

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR approved by Standards Committee on January 18, 2008.

Proposed Action Plan and Description of Current Draft:

The drafting team is asking the Standards Committee to authorize posting the SAR and associated modified standards for a 45-day comment period from January 23–March 7, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and request authorization to move forward to pre-ballot posting.	March 14, 2008
2. Post for 30-day pre-ballot period.	March 17–April 15, 2008
3. Conduct initial ballot.	April 16–25, 2008
4. Post response to comments on initial ballot.	April 30, 2008
5. Conduct recirculation ballot.	May 1–10, 2008
6. Board adoption.	May 16, 2008
7. Submit to regulatory authorities for approval.	May 15, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, ~~2007~~2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied.~~

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

---

[2] The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Violation Severity Levels (To be added once approved by the VSL Ballot Pool)

~~**3.Levels of Non-Compliance (Does not apply to the Western Interconnection)**~~

~~**3.1.Level 1:** There shall be a level one non-compliance if either of the following conditions exists:~~

~~**3.1.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~**3.1.2**No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~**3.2.Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.~~

~~**3.3.Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~**3.3.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~**3.3.2**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the seven required topics in R3.~~

~~**3.4.Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.~~

3. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~Outages~~ outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading ~~O~~outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking

1	November 1, 2006	Adopted by Board of Trustees	New

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

January 24, 2007

Re: Comment Periods Open

The Standards Committee announces the following standards actions:

Proposed Revisions to Timing Tables in INT-005-2, INT-006-2, and INT-008-2 Posted for 45-day Comment Period

A set of proposed modifications to INT-005-1 — Interchange Authority Distributes Arranged Interchange, INT-006-1 — Response to Interchange Authority, and INT-008-1 — Interchange Authority Distributes Status, have all been posted for a 45-day comment period from January 24–March 8, 2008.

In 2007, stakeholders approved a set of Urgent Action modifications to the Timing Tables in INT-005-1, INT-006-1, and INT-008-1.

The modifications lengthened the reliability assessment period for WECC from 5 minutes to 10 minutes for e-tags submitted less than 1 hour and greater than 20 minutes prior to ramp start. Under the *Reliability Standards Development Procedure*, these Urgent Action modifications will expire unless they are replaced with permanent changes that go through the full standards development procedure.

The Coordinate Interchange Timing Table Standard Drafting Team made additional modifications to the timing tables in response to stakeholder comments and made a minor clarification to INT-006-2, Requirement R1. The revised standards have been posted for comment.

Please use this comment form to submit comments on the proposed modifications.

SAR to Revise FAC-010-1 and FAC-011-1 and Proposed Changes to FAC-010-1 and FAC-011-1 to Comply with FERC Order 705 Posted for 45-day Comment Period

A new SAR for Project 2008-04 and proposed changes to modify FAC-010-1 — System Operating Limits Methodology for the Planning Horizon and FAC-011-1 — System Operating Limits Methodology for the Operations Horizon have all been posted for a 45-day comment period from January 24–March 8, 2008.

In Order 705, FERC approved FAC-010-1 — System Operating Limits Methodology for the Planning Horizon, FAC-011-1 — System Operating Limits Methodology for the Operations Horizon, and FAC-014-1 — Establish and Communicate System Operating Limits, and directed NERC to make changes to each of these standards. The changes fall into two categories — those that are subject to stakeholder input and those that are not subject to stakeholder input. The SAR is limited to addressing the directives in Order 705 that are subject to stakeholder input — retiring a definition; removing an example from a requirement; and adding a footnote for clarity to both standards.

Please use this comment form to submit comments on this SAR.

SAR to Revise FAC-011-1 to Address Credible Multiple Contingencies Posted for 30-day Comment Period

A new SAR for Project 2008-05 to Modify FAC-011-1 — System Operating Limits Methodology for the Operations Horizon has been posted for a 30-day comment period from January 24–February 22, 2008.

The SAR proposes modifying FAC-011-1 to require consideration of credible multiple element contingency events for determining SOLs in the operating horizon, as required by TPL-003-0 and FAC-010-1 for the planning horizon.

Please use this comment form to submit comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Implementation Plan for FAC-010-2 and FAC-011-2

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards
FAC-010-1 and FAC-011-1 should be retired when the proposed standards become effective.

Compliance with Standards
Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date
The proposed effective dates are the same for all regulatory jurisdictions:

- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☐ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Jason Shaver	
Organization:	American Transmission Company	
Telephone:	262 506 6885	
E-mail:	jshaver@atcllc.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
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> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
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Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"
The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

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The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☐ Yes

   ☒ No

   Comments: Please see our comments below

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: In Order 705, FERC states that it will approve FAC-010-1, Requirement R2.3, and the ERO should ensure that the clarification developed in response to Order No. 693 is made to TPL-002-0. Since FAC-010, and Requirement R2.3.1 specifically, are to reflect the system performance requirements specified in TPL-002, the ERO should modify the text of FAC-010 R2.3.1 to reflect the clarification that FERC desires in TPL-002, after the change has been made to TPL-002.

   The text of Footnote 2 should be incorporated into FAC-010 after TPL-002 is changed. Otherwise, the Footnote 2 text is contradictory to the existing R2.3.1 text and Table 1, Footnote b of TPL-002-0.

   The text of Footnote 2 is applicable to R2.3.1, not R2.3.2 and R2.3.3. Therefore, when this text is added, then it should be added to R2.3.1, not R2.3.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☒ No

   Comments: The SAR should explain the consequence of deleting the language from requirement 2.3.2. The language in question provides an example for Requirement 2.3.2. How should the statement "...if the real-time operating conditions are more adverse than anticipated in the corresponding studies" be interpreted if it is not load greater than studied?

   As a Transmission Owner and Operator we are not responsible for load forecasting but we use the load forecasting provided to us for our studies. Is anyone in violation of this Standard if the load forecasted is lower than the actual operating conditions?

The SDT should confirm that this standard dictates what has to be included in a methodology and that it does not dictate how in real-time a Transmission Operator is to act to control to their SOLs/IROLs. This confirmation is needed because other NERC standards address what the Transmission Operator has to do in real-time and that this standard is not one of them.

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

☒ Yes

☐ No

Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

Comments: Issue 1:
ATC interprets that changing its SOL methodology to be compliant with a new FAC-010 standard and establishing new SOLs to be compliant with the FAC-014-1 standard is separate from being compliant with the existing TPL-002-0 standard. The new FAC-010 may lead to the identification of new system operating limit violations, but compliance with TPL-002-0 still depends on dealing with the existing system performance limit violations specified in TPL-002-0.

Therefore, mandatory compliance with FAC-010-2 would involve rewording the SOL methodology by 7/1/2008 to reflect the requirements in the standard. Mandatory compliance with FAC-014-1 by 1/1/2009 would involve recalculating and communicating any revised SOLs based on any changes that were made to the planning horizon SOL methodology. Mandatory compliance with TPL-002-0 would continue involve meeting the system performance requirements specified in this standard, until the standard is changed.

Issue 2:
The SDT should explain why the numbering of Requirement 2.4 in FAC-011-1 and Requirement 2.3.3 in FAC-010-1 are different? Both of these two requirement contain exactly the same language but in FAC-010 is a sub-requirement of R2.3 and in FAC-011 it a sub-requirement of R2.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Phil Park	
Organization:	British Columbia Transmission Corporation	
Telephone:	604 699 7340	
E-mail:	phil.park@bctc.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: We have a number of comments. 1. The footnote should be to R2.3.1, not R2.3. 2. Should consider replacing R2.3.1 with the statement in the footnote. 3. Consider the following for R2.3.1: "Planned or controlled interruption of electric supply to radial customers or some local network customers directly served by the elements that are removed from service as a result of the contingency."

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☐ Yes

   ☒ No

   Comments: The word "outage" following "Cascading" can also be deleted. It is redundant with respect to the definition of Cascading.

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Dale Bodden	
Organization:	CenterPoint Energy	
Telephone:	713-207-2806	
E-mail:	dale.bodden@centerpointenergy.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

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Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

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The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards

Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: The ATFN SDT is currently refining the definition of Consequential Load Loss based on FERC directives and industry comments. This SDT and the ATFN SDT must coordinate and any footnote included in FAC-010-2 and FAC-011-2 clarifying Consequential Load Loss should contain the latest version of the ATFN SDT definition for the term.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

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RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jack Kerr	
Organization:	Dominion Virginia Power	
Telephone:	804-273-3393	
E-mail:	jack.kerr@dom.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
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Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

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> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
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Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

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The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: It comes close, but there is still an opportunity to provide more clarity. Even though Order 705 references requirement 2.3 in the discussion of consequential load, the specific concern stated in the Order (paragraph 50) was with the wording of requirement 2.3.1 which is quoted verbatim in that paragraph. Therefore, if a footnote is to be used, it should apply to 2.3.1 only instead of being attached to 2.3. The wording of the proposed footnote is based upon the definition of consequential load provided in Order 693 which limits the interruption of electric supply to the load that is directly served by the elements that are removed from service as a result of the contingency. However, the wording of 2.3.1 refers to load in "the affected area" as well as load "connected to or served by the Faulted Facility" and therefore seems inconsistent with the explanatory footnote (or at least not totally clear). Consequently, a better solution would be to eliminate the footnote on 2.3 and incorporate the definition of consequential load into a revision of 2.3.1 that would read:

   R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name: Greg Rowland		
Organization: Duke Energy		
Telephone: 704-382-5348		
E-mail: gdrowland@dukeenergy.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
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Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)

Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards

Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: The footnote is insufficiently clear and does not reflect the latest work of the TPL Standards Drafting Team. When FAC-010-2 and FAC-011-2 go to ballot, they must contain the latest work of the ATFNSDT work on TPL-001-1 defining Consequential Load. This is supported by FERC's directive in paragraph 53 of Order No. 705 : "Order No. 693 stated that the transmission system should not be planned to permit load shedding for a single contingency. Order No. 693 directed NERC to clarify the planning Reliability Standard TPL-002-0 accordingly. The Commission reaches the same conclusion here. We will approve Reliability Standard FAC-010-1, Requirement R2.3 and the ERO should ensure that the clarification developed in response to Order No. 693 is made to the FAC Reliability Standards as well."

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments: Standards TPL-001-0 through TPL-004-0 are being rewritten and consolidated into a new TPL-001-1. FAC-010-2 requirements R2.4 and R2.5 contain references to TPL-003, which will necessitate conforming changes to FAC-010-2 when TPL-001-1 is approved.

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Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Ron Szymczak
Organization:	ComEd Transmission Planning
Telephone:	630-437-2795
E-mail:	ronald.szymczak@exeloncorp.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
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> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
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The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☐ Yes

   ☒ No

   Comments: In both standards, FAC-010 and FAC-011, in section R2.2 the following wording change is required: "and Cascading (delete the word "outages") or uncontrolled separation shall not occur"

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Doug Hohlbaugh
Organization:	FirstEnergy Corp.
Telephone:	(330) 384-4698
E-mail:	hohlbaughdg@firstenergycorp.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Sam Ciccone	FE	RFC	

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

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(Order 693 defined consequential load, at P 1794 n.461: “Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.”)

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that “load greater than studied” cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an ‘example’ and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system’s response to a single Contingency, the following shall be acceptable[2]:
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Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)

Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don’t include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards

Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “FAC-010 and FAC-011” by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments: We agree that the FERC directives have been addressed, however, with regard to the Violation Severity Levels (VSL), it is our understanding the the VSL drafting team (Proj. 2007-23) did not develop VSLs for the FAC-010, -011, and -014 standards and only focused on the initially FERC approved 83 standards. This SAR should more correctly state that the "VSLs will be developed by the FAC SDT and replace the levels of non-compliance" [Note that VSLs for FAC-014-1 should also be developed and in the scope].

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: We suggest that the FAC SDT consider coordination with the ATFN SDT (Proj. 2006-02) since the AFTN team has already proposed, in their initial draft of TPL-001-1, an official NERC term for "Consequational Load Loss".

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

Comments: We suggest adding the Violation Risk Factors (VRF) to the text of each requirement in each standard [Note, this should also include adding the VRFs to FAC-014-1].

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RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Linda Campbell		
Organization: FRCC		
Telephone: 813-207-7961		
E-mail: lcampbell@frcc.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC Compliance Committee

Lead Contact: Linda Campbell

Contact Organization: FRCC

Contact Segment: 10

Contact Telephone: 813-207-7961

Contact E-mail: lcampbell@frcc.com

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments: The Compliance Monitoring Responsibility should be the Regional Entity, not the Regional Reliability Organization. The RE's have the authority through their approved Delegation Agreements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Alessia Dawes	
Organization:	Hydro One Networks	
Telephone:	416-345-5286	
E-mail:	alessia.dawes@hydroone.com	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Group Comments (Complete this page if comments are from a group.)

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Lead Contact:

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Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie (HQT)	
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E-mail:	champagne.roger.2@hydro.qc.ca	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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   ☒ Yes

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsettiW@ieso.ca	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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Group Comments (Complete this page if comments are from a group.)

Group Name:	ISO RTO Council/Standards Review Committee (SRC)
Lead Contact:	Charles Yeung
Contact Organization:	Southwest Power Pool
Contact Segment:	2
Contact Telephone:	832-724-6142
Contact E-mail:	cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Patrick Brown	PJM	RFC/SERC	2
Jim Castle	NYISO	NPCC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
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The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

   The ISO RTO Council has filed a Request for Clarification or in the alternative Rehearing. We ask the NERC SDT to consider any further clarifiying language FERC requests if they impact FAC-010 and FAC-011.

Regarding Footnote (1) on both FAC-010 & 011 - there is no apparent reason to include Footnote (1) as it is editorial, it is not a requirement and it adds no additional clarity. The Requirements already identify what must be studied - which is the purpose of the standard.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Ron Mazur
Organization:	Manitoba Hydro
Telephone:	1-204-669-2735
E-mail:	rwmazur@hydro.mb.ca

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

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To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
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> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

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Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

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The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☐ Yes

   ☐ No

   Comments:

   MH does not see the term "consequential load" used in R2.3 of FAC-10-1 (reproduced below), so what needs to be clarified?

   R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
   R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
   R2.3.2. System reconfiguration through manual or automatic control or protection actions.
   R2.3.3. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: MH does not see the term "consequential load" used in R2.3 of FAC-10-1, so what needs to be clarified?

   MH disagrees with the footnote 2. R2.3.1 clearly defines that radial load or some local network customers connected to or suplied by the Faulted facility or affected areas can be interrupted. The footnote narrows the defintion to only direct connected load, which is not appropriate - creates a conflict with requirement.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

☒ Yes

☐ No

Comments: The approved definition of cascading is clear. The word "outages' could be removed from the standards without changing the understanding.

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

Comments: MH does not see a reliability need to define SOLs in the planning horizon and believes the Standard FAC-010-1 should be withdrawn. Operators do not use future SOLs, so who benefits from the extra work required to comply with this SAR?

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RELIABILITY CORPORATION

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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Group Comments (Complete this page if comments are from a group.)

Group Name:	Midwest ISO Stakeholders Standards Collaborators
Lead Contact:	Marie Knox
Contact Organization:	Midwest ISO
Contact Segment:	2
Contact Telephone:	317-249-5264
Contact E-mail:	mknox@midwestiso.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Dede Subakti	Midwest ISO	RFC, SERC, MRO, SPP	2
Carol Gerou	Minnesota Power	MRO	1,3,5
Jeanne Kurzynowski	Consumers Energy Company	RFC	3,4,5
Jim Cyrulewski, P.E.	JDRJC Associates	RFC	8
Jason Marshall	Midwest ISO	RFC,MRO,SERC,SPP	2

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   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: The footnote should also explicitly exclude all actions resulting from the operation of UFLS and UVLS.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☒ No

   Comments: I agree with the drafting teams removal of the phrase "e.g., load greater than studied". However, the drafting team should delineate between the contingency conditions from the system conditions. The separate system conditions are the reason to adjust generation and not the previously discussed contingency; therefore, the separate system conditions should be emphasize so that there is no missunderstanding.

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☐ Yes

   ☒ No

   Comments: Should text "(or condition)" be added to the Cascading definition listed in the SAR. Plus, where is the cascading definition in the NERC FAC-010-2 standard? I don't see this definition listed in the NERC FAC-010-2 standard.

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Comments: Yes, In the brief description section of the SAR (page SAR-2). The violation Risk Factors are suggested to be updated in accordance with FERC order 750. Isn't this FERC order 705?

The VSL drafting team did not create VSLs for these two standards. Thus, creation of VSLs should be added to the scope of this SAR.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Group Comments (Complete this page if comments are from a group.)

Group Name: MRO NERC Standards Review Sub-Committee

Lead Contact: Pam Oreschnick

Contact Organization: XCEL

Contact Segment: 1,3,5,6

Contact Telephone: 612-337-2376

Contact E-mail: pamela.j.oreschnick@xcelenergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPA	MRO	3,4,5,6
Terry Bilke	MISO	MRO	2
Robert Coish	MHEB	MRO	1,3,5,6
Carol Gerou	MP	MRO	1,3,5,6
Jim Haigh	WAPA	MRO	1,6
Ken Goldsmith	ALTW	MRO	4
Tom Mielnik	MEC	MRO	1,3,5,6
Dave Rudolph	BEPC	MRO	1,3,5,6
Eric Ruskamp	LES	MRO	1,3,5,6
Joseph Knight	GRE	MRO	1,3,5,6
Larry Brusseau	MRO	MRO	10
Michael Brytowski	MRO	MRO	10
27 Members	Not mentioned above	MRO	10

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1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☒ No

   Comments: The MRO agrees with the drafting teams removal of the phrase "e.g., load greater than studied"; however, the drafting team should further clairify the subrequirement. The MRO finds the use of 'or' in the subrequirement to be very confusing. The MRO also would like clairification on 'Prior Outage'.

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments: Yes, In the brief description section of the SAR (page SAR-2). The Violation Risk Factors are suggested to be updated in accordance with FERC order 750, should be FERC Order 705.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	NPCC Regional Standards Committee
Lead Contact:	Guy Zito
Contact Organization:	NPCC
Contact Segment:	Regional Standards
Contact Telephone:	212-840-1070
Contact E-mail:	Gzito@npcc.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Lee Pedowicz	NPCC	NPCC	10
Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
Randy MacDonald	New Brunswick System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1, 2
Ronald Hart	Dominion Resources, Inc.	NPCC	5
Biju Gopi	Independent Electricity System Operator	NPCC	2
Murale Gopinathan	Northeast Utilities	NPCC	1, 4
Michael Ranalli	National Grid	NPCC	1, 4
Kathleen Goodman	ISO New England	NPCC	2
Ralph Rufrano	New York Power Authority	NPCC	1, 4, 5, 6, 9
Peter Yost	Consolidated Edison Company of New York, Inc.	NPCC	1, 4, 5, 6
Roger Champagne	Hydro-Quebec TransEnergie	NPCC	1, 2
Gregory Campoli	New York Independent System Operator	NPCC	2
Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
Donald Nelson	Massachusetts Department of Public Utilities	NPCC	9
David Kiguel	Hydro One	NPCC	1, 3

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	John P. Mayhan	
Organization:	Omaha Public Power District	
Telephone:	(402) 552-5173	
E-mail:	jmayhan@oppd.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

Order 705 — Section 2 — Loss of Consequential Load — (paragraphs 50–53) directs NERC to clarify, in both FAC-010-1 Requirement R2.3 and FAC-011-1 Requirement R2.3 what is meant by the term, "consequential load."

(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

To address this directive, the drafting team added the following footnote to R2.3:

> The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.

Order 705 — Section 4 — Load Forecast Error — (paragraphs 59–70) directs NERC to modify R2.3.2 to clarify that "load greater than studied" cannot be treated as a contingency and suggested that elimination of the phrase from the requirement would be a sufficient remedy.

To address this directive, the drafting team modified R2.3.2 to eliminate the identified phrase. This was intended to be an 'example' and omitting this does not adversely impact the requirement. The modification is shown in context below:

> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: The placement of the superscript 2 at the end of R2.3 of FAC-011 makes R2.3.2 inconsistent with R2.3, because R2.3.2 allows interruption of other network customers under certain conditions. It would seem to be better to place the superscript 2 at the end of R2.3.1 rather than at the end of R2.3, in both FAC-010 and FAC-011.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☐ Yes

   ☒ No

   Comments: Withdrawal of the definition for Cascading Outage is acceptable, but the manner in which FAC-010 and FAC-011 were revised makes for awkward reading, because the approved definition of Cascading treats the term Cascading as a noun, while the revised versions of FAC-010 and FAC-011 use the term as an adjective (modifying the word outages). It would seem to be more proper grammatically, in FAC-010 and FAC-011, to replace the words Cascading Outages by just the word Cascading (i.e., striking the word Outages).

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Stan Southers / Ellis Rankin	
Organization:	Oncor Electric Delivery Company LLC	
Telephone:	214-486-2084 / 214-743-6825	
E-mail:	stan.southers@oncor.com / erankin@oncor.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

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> "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

Order 705 — Section E — Violation Risk Factors and Violation Severity Levels (paragraphs 129–179)
Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

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The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards
Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments: Oncor endorses the changes as made by the standards drafting team.

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

Please use this form to submit comments on the SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon. Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "FAC-010 and FAC-011" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or by telephone at 813-468-5998.

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Name:		
Organization:		
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Group Comments (Complete this page if comments are from a group.)

Group Name: Pepco Holdings, Inc. - Affiliates

Lead Contact: Richard J. Kafka

Contact Organization: Pepco Holdings, Inc.

Contact Segment: 1

Contact Telephone: 301-469-5274

Contact E-mail: rjkafka@pepcoholdings.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Bill Mitchell	Delmarva Power	RFC	1
John Radman	Potomac Electric Power Co.	RFC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FERC Order 705 directed NERC to make certain modifications to FAC-010 and FAC-011. There are some directives that mandate specific Violation Risk Factor modifications, and NERC staff is responding to these directives. The directives in the Order that are within the scope of this SAR and subject to stakeholder consensus include the following:

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(Order 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.")

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> R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:
>
> > R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
> >
> > R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied~~.
> >
> > R2.3.3. System reconfiguration through manual or automatic control or protection actions.

Order 705 — Section D — New Glossary Terms — Cascading (paragraphs 98–117) remands to NERC its proposed definition of "Cascading Outage"

The drafting team does not intend to pursue a revised definition and proposes withdrawing the definition of "Cascading Outage" and using the already approved definition of "Cascading" in the revised standards.

To address this directive, the drafting team revised the capitalization in FAC-010 and FAC-011 so that the word "Cascading" is capitalized, and the word, "outage" is not capitalized to signify that the word, "Cascading" is defined term in the NERC Glossary of Terms Used in

Reliability Standards. The drafting team does not believe that use of the originally approved definition of "Cascading" will have an adverse impact on the use of these standards. The approved definition of "Cascading" is:

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Note that Order 705 also included directives relative to Violation Risk Factors and Violation Severity Levels.

The Commission directed NERC to submit nine modified and one new Violation Risk Factor (VRF) no later than 90 days before the effective date of the associated Standard (July 1, 2008 for FAC-010 and October 1, 2008 for FAC-011). The Commission identified specifically which VRFs must be changed and identified specifically what the new VRF must be and indicated that no other product is acceptable. Since the modification of these VRFs don't include an opportunity for stakeholder comment, the drafting team is not asking for comments on these modifications.

The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

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The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: The proposed footnote, if it is to be used, should be appled to R2.3.1 only and not to R2.3 in general. The wording of the proposed footnote limits the interruption of electric supply to the load directly served by the elements that are removed from service by the single contingency. The footnote is silent on "affected area" load. In order to clarify R2.3.1 would be better to eliminate the proposed footnote and modify R2.3.1 with the following:

   R2.3.1 Planned or controlled interruption of electric supply to radial customersor or some local network customers load that is directly served by the elements that are removed from service as result of the contingency.

3. Do you agree with the drafting team’s removal of the phrase “e.g., load greater than studied?”

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Mark Kuras		
Organization: PJM		
Telephone: 610-666-8924		
E-mail: kuras@pjm.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☐ Yes

   ☒ No

   Comments: Since the term consequential load is used in other standards, this definition should be added to the NERC Glossary. This should be left up to the standard drafting team and consensus of industry comments.

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☐ Yes

   ☒ No

   Comments: Removing this example would make the standard less clear but this removal does not change the intent. This should be left up to the standard drafting team and consensus of industry comments.

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments: The proposed use of Cascading adequately covers the intent of the Standard.

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments: Revision of the standards should be left up to the standard drafting team and consensus of industry comments.

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RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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Group Comments (Complete this page if comments are from a group.)

Group Name:	Public Service Commission of South Carolina
Lead Contact:	Phil Riley
Contact Organization:	Public Service Commission of South Carolina
Contact Segment:	9
Contact Telephone:	803-896-5154
Contact E-mail:	philip.riley@psc.sc.gov

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Operating Reliability Working Group (ORWG)	
Organization:	Southwest Power Pool	
Telephone:	501-614-3241	
E-mail:	rrhodes@spp.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name: Operating Reliability Working Group (ORWG)

Lead Contact: Robert Rhodes

Contact Organization: Southwest Power Pool

Contact Segment: 2

Contact Telephone: 501-614-3241

Contact E-mail: rrhodes@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Brian Berkstresser	Empire District Electric	SPP	1,3,5
Don Hargrove	Oklahoma Gas & Electric	SPP	1,3,5
Allen Klassen	Westar Energy	SPP	1,3
Pete Kuebeck	Oklahoma Gas & Electric	SPP	1,3,5
Scott Lockwood	American Electric Power	SPP	1,3,5
Robert Rhodes	Southwest Power Pool	SPP	2
Jim Useldinger	Kansas City Power & Light	SPP	1,3,5
Bryan Taggart	Westar Energy	SPP	5,6

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The Commission also directed that the Levels of Non-compliance be replaced with Violation Severity Levels (VSLs). The Violation Severity Levels is working to develop a set of VSLs for these standards, and the drafting team will ensure that the VSLs developed by the VSL drafting team are added to these standards once they approved by their Ballot Pool. The Commission directed WECC to replace the Levels of Noncompliance for the WECC Regional Differences in both FAC-010 and FAC-011 with VSLs, and WECC is working to develop those. Once WECC develops these VSLs using its approved process, the Levels of Noncompliance will be replaced with WECC-specific VSLs.

Reason for Parallel Posting of SAR and Revised Standards

Because the proposed modifications are relatively simple, and ideally they should be implemented before the first standard in the set becomes effective, the drafting team asked the Standards Committee for authorization to post both the SAR and the proposed standards at the same time. The Reliability Standards Development Procedure does allow this parallel posting, and in this case should allow the drafting team to complete its work without having to use the Urgent Action process. The goal is to have the modifications in place before July 1, 2008, which is the FERC-approved effective date for FAC-010-1.

The Facility Ratings Drafting Team would like to receive comments on the SAR and the proposed revisions to the standards. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "FAC-010 and FAC-011" by **March 7, 2008**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

   ☒ Yes

   ☐ No

   Comments:

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Report for Revisions to FAC-010-1 and FAC-011-1 for FERC Order 705 (Project 2008-04)

The SAR drafting team thanks all commenters who submitted comments on SAR and associated proposed modifications to FAC-010 — System Operating Limits Methodology for the Planning Horizon and FAC-011 — System Operating Limits Methodology for the Operations Horizon.

This SAR and associated standards were posted for a 45-day public comment period from January 24 through March 7, 2008. The standard drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were 22 sets of comments, including comments from more than 130 different people from more than 50 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team has revised the SAR and standards to include development of Violation Severity Levels for FAC-010, FAC-011, and FAC-014 –and to remove the references to "loss of consequential load." The drafting team is posting the SAR and revised standards for a 30-day comment period.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Facility_Ratings_Project_2008-04.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G1)	Alberta Electric System Operator		x								
2.	Ken Goldsmith (G3)	ALTW				x						
3.	Scott Lockwood (G6)	American Electric Power	x		x		x					
4.	Jason Shaver	American Transmission Company	x									
5.	Dave Rudolph (G3)	BEPC	x		x		x	x				
6.	Phil Park	British Columbia Transm. Corp.		x								
7.	Brent Kingsford (G1)	California ISO		x								
8.	Dale Bodder	CenterPoint Energy	x									
9.	Ron Szymczak	ComEd Transmission Planning										
10.	Peter Yost (G4)	Consolidated Edison Co. of NY, Inc.	x			x	x	x				
11.	Jeanne Kurzynowski (G2)	Consumers Energy Company			x	x	x					
12.	Bill Mitchell (G5)	Delmarva Power	x									
13.	Ronald Hart (G4)	Dominion Resources, Inc.					x					
14.	Jack Kerr	Dominion Virginia Power	x									
15.	Greg Rowland	Duke Energy	x		x							
16.	Brian Berkstresser (G6)	Empire District Electric	x		x		x					
17.	Steve Myers (G1)	ERCOT		x								
18.	Doug Hohlbaugh/Sam Ciccone	FirstEnergy Corp.	x		x		x	x				
19.	Linda Campbell	Florida Reliability Coordinating Council										x
20.	Joseph Knight (G3)	GRE	x		x		x	x				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
21.	Alessia Dawes	Hydro One Networks, Inc.	x		x							
22.	David Kiguel (G4)	Hydro One Networks, Inc.	x		x							
23.	Sylvain Clermont (G4)	Hydro-Québec TransÉnergie	x	x								
24.	Roger Champagne (I) (G4)	Hydro-Québec TransÉnergie (HQT)	x									
25.	Biju Gopi (G4)	Independent Electricity SO		x								
26.	Ron Falsetti (I) (G1)	Independent Electricity SO		x								
27.	Kathleen Goodman (G4)	ISO New England		x								
28.	Matt Goldberg (G1)	ISO New England		x								
29.	Jim Cyrulewski (G2)	JDRJC Associates								x		
30.	Jim Useldinger (G6)	Kansas City Power & Light Co.	x		x		x					
31.	Eric Ruskamp (G3)	Lincoln Electric System	x		x		x	x				
32.	Donald Nelson (G4)	MA Dept. of Public Utilities									x	
33.	Robert Coish (G3)	Manitoba Hydro	x		x		x	x				
34.	Ron Mazur (G1)	Manitoba Hydro	x		x		x	x				
35.	Tom Mielnik (G3)	MEC	x		x		x	x				
36.	Bill Phillips (G1)	Midwest ISO		x								
37.	Dede Subakti (G2)	Midwest ISO		x								
38.	Jason Marshall (G2)	Midwest ISO		x								
39.	Marie Knox (G2)	Midwest ISO		x								
40.	Terry Bilke (G3)	Midwest ISO		x								
41.	Larry Brusseau (G3)	Midwest Reliability Organization										x
42.	Michael Brytowski (G3)	Midwest Reliability Organization										x
43.	Carol Gerou (G2) (G3)	Minnesota Power	x		x		x					
44.	Michael Ranalli (G4)	National Grid	x			x						
45.	Randy MacDonald (G4)	New Brunswick System Operator		x								
46.	Gregory Campoli (G4)	New York ISO		x								
47.	Jim Castle (G1)	New York ISO		x								
48.	Ralph Rufrano (G4)	New York Power Authority	x			x	x	x			x	

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
49.	Guy V. Zito (G4)	Northeast Power Coord. Council										x
50.	Lee Pedowicz (G4)	Northeast Power Coord. Council										x
51.	Murale Gopinathan (G4)	Northeast Utilities	x			x						
52.	Don Hargrove (G6)	Oklahoma Gas & Electric	x		x							
53.	Pete Kuebeck (G6)	Oklahoma Gas & Electric	x		x		x					
54.	John P. Mayhan	Omaha Public Power District	x		x			x				
55.	Stan Southers/Ellis Rankin	Oncor Electric Delivery Co., LLC	x									
56.	Brian Gooder (G4)	Ontario Power Generation Inc.					x					
57.	Richard J. Kafka (G5)	Pepco Holdings, Inc.	x									
58.	Mark Kuras (G5)	PJM Interconnection		x								
59.	Patrick Brown (G1)	PJM Interconnection		x								
60.	John Radman (G5)	Potomac Electric Power Company	x									
61.	Phil Riley	PSC of South Carolina									x	
62.	Charles Yeung (G1)	Southwest Power Pool										x
63.	Robert Rhodes (G6)	Southwest Power Pool										x
64.	Brian Evans-Mongeon (G4)	Utility Services, LLC						x				
65.	Jim Haigh (G3)	WAPA	x					x				
66.	Allen Klassen (G6)	Westar Energy	x		x							
67.	Bryan Taggart (G6)	Westar Energy					x	x				
68.	Neal Balu (G3)	WPA			x	x	x	x				
69.	Pam Oreschnick (G3)	Xcel	x		x		x	x				

I – Individual
G1 – ISO/RTO Council
G2 – Midwest ISO Stakeholders Standards Collaborators
G3 – Midwest Reliability Organization
G4 – NPCC Regional Standards Committee
G5 – Pepco Holdings, Inc.
G6 – SPP Operating Reliability Working Group

Index to Questions, Comments, and Responses

1. Do you agree that the scope of the SAR adequately addresses the directives in FERC Order 705 that are relative to FAC-010 and FAC-011? If you believe that the drafting team has missed a directive, please identify the directive by paragraph number in your comments.

Summary Consideration: Most commenters agreed with the modifications made by the drafting team.

#1 – Commenter	Yes	No	Comment
Manitoba Hydro			MH does not see the term "consequential load" used in R2.3 of FAC-10-1 (reproduced below), so what needs to be clarified? R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. System reconfiguration through manual or automatic control or protection actions. R2.3.3. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
Response: The drafting team has elected to remove the footnote that referenced "consequential load." This term is currently being defined as part of the revisions to the TPL series of standards with the Assess Transmission Future Needs Standard Drafting Team.			
American Transmission Company		x	Please see our comments below.
Response: Please see the response to your comments below.			
FirstEnergy Corp.	x		We agree that the FERC directives have been addressed, however, with regard to the Violation Severity Levels (VSL), it is our understanding the the VSL drafting team (Proj. 2007-23) did not develop VSLs for the FAC-010, -011, and -014 standards and only focused on the initially FERC approved 83 standards. This SAR should more correctly state that the "VSLs will be developed by the FAC SDT and replace the levels of non-compliance" [Note that VSLs for FAC-014-1 should also be developed and in the scope].
Response: When the requesters developed the SAR they thought the VSL DT had developed VSLs for FAC-010, FAC-011 and FAC-014. A new SAR is underway to develop a new set of VSLs for the EOP standards and for FAC-010, FAC-011 and FAC-014.			

#1 – Commenter	Yes	No	Comment
Oncor Electric Delivery	x		Oncor endorses the changes as made by the standards drafting team.
Response: The drafting team appreciates your support.			
British Columbia Transm. Corp.	x		
CenterPoint Energy	x		
Dominion Virginia Power	x		
Duke Energy	x		
ComEd Transmission Planning	x		
FRCC Compliance Committee	x		
Hydro One Networks, Inc.	x		
Hydro-Québec/TransÉnergie	x		
Independent Electricity SO	x		
IRC Standards Review Committee	x		
Midwest ISO	x		
Midwest Reliability Organization	x		
Pepco Holdings, Inc.	x		
PJM Interconnection	x		
PSC of South Carolina	x		
SPP Operating Reliability WG	x		

2. Do you agree that the footnote added to FAC-010 and FAC-011 addresses the concern identified in Order 705 relative to loss of consequential load?

Summary Consideration: The ATF SDT working on revisions to the "TPL" series of standards has proposed a NERC definition of "Consequential Load Loss." Because Order 705 did not direct NERC to include this footnote in FAC-010 and FAC-011, and because NERC has already made a commitment to modify the ATC related standards and the FAC related standards to align with the TPL standards when they are revised, the drafting team has elected to remove the footnote from the revised standards. This shall serve as a single response to all comments submitted in response to this question.

#2 – Commenter	Yes	No	Comment
American Transmission Company		x	In Order 705, FERC states that it will approve FAC-010-1, Requirement R2.3, and the ERO should ensure that the clarification developed in response to Order No. 693 is made to TPL-002-0. Since FAC-010, and Requirement R2.3.1 specifically, are to reflect the system performance requirements specified in TPL-002, the ERO should modify the text of FAC-010 R2.3.1 to reflect the clarification that FERC desires in TPL-002, after the change has been made to TPL-002. The text of Footnote 2 should be incorporated into FAC-010 after TPL-002 is changed. Otherwise, the Footnote 2 text is contradictory to the existing R2.3.1 text and Table 1, Footnote b of TPL-002-0. The text of Footnote 2 is applicable to R2.3.1, not R2.3.2 and R2.3.3. Therefore, when this text is added, then it should be added to R2.3.1, not R2.3.
British Columbia Transm. Corp.		x	We have a number of comments. 1. The footnote should be to R2.3.1, not R2.3. 2. Should consider replacing R2.3.1 with the statement in the footnote. 3. Consider the following for R2.3.1: "Planned or controlled interruption of electric supply to radial customers or some local network customers directly served by the elements that are removed from service as a result of the contingency."
CenterPoint Energy		x	The ATFN SDT is currently refining the definition of Consequential Load Loss based on FERC directives and industry comments. This SDT and the ATFN SDT must coordinate and any footnote included in FAC-010-2 and FAC-011-2 clarifying Consequential Load Loss should contain the latest version of the ATFN SDT definition for the term.
Dominion Virginia Power		x	It comes close, but there is still an opportunity to provide more clarity. Even though Order 705 references requirement 2.3 in the discussion of consequential load, the specific concern stated in the Order (paragraph

#2 – Commenter	Yes	No	Comment
			50) was with the wording of requirement 2.3.1 which is quoted verbatim in that paragraph. Therefore, if a footnote is to be used, it should apply to 2.3.1 only instead of being attached to 2.3. The wording of the proposed footnote is based upon the definition of consequential load provided in Order 693 which limits the interruption of electric supply to the load that is directly served by the elements that are removed from service as a result of the contingency. However, the wording of 2.3.1 refers to load in "the affected area" as well as load "connected to or served by the Faulted Facility" and therefore seems inconsistent with the explanatory footnote (or at least not totally clear). Consequently, a better solution would be to eliminate the footnote on 2.3 and incorporate the definition of consequential load into a revision of 2.3.1 that would read: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers limited to the load that is directly served by the elements that are removed from service as a result of the contingency.
Duke Energy		x	The footnote is insufficiently clear and does not reflect the latest work of the TPL Standards Drafting Team. When FAC-010-2 and FAC-011-2 go to ballot, they must contain the latest work of the ATFNSDT work on TPL-001-1 defining Consequential Load. This is supported by FERC's directive in paragraph 53 of Order No. 705 : "Order No. 693 stated that the transmission system should not be planned to permit load shedding for a single contingency. Order No. 693 directed NERC to clarify the planning Reliability Standard TPL-002-0 accordingly. The Commission reaches the same conclusion here. We will approve Reliability Standard FAC-010-1, Requirement R2.3 and the ERO should ensure that the clarification developed in response to Order No. 693 is made to the FAC Reliability Standards as well."
FirstEnergy Corp.		x	We suggest that the FAC SDT consider coordination with the ATFN SDT (Proj. 2006-02) since the AFTN team has already proposed, in their initial draft of TPL-001-1, an official NERC term for "Consequential Load Loss".
Manitoba Hydro		x	MH does not see the term "consequential load" used in R2.3 of FAC-10-1, so what needs to be clarified? MH disagrees with the footnote 2. R2.3.1 clearly defines that radial load or some local network customers connected to or suplied by the Faulted

#2 – Commenter	Yes	No	Comment
			facility or affected areas can be interrupted. The footnote narrows the defintion to only direct connected load, which is not appropriate - creates a conflict with requirement.
Midwest ISO		x	The footnote should also explicitly exclude all actions resulting from the operation of UFLS and UVLS.
Omaha Public Power District		x	The placement of the superscript 2 at the end of R2.3 of FAC-011 makes R2.3.2 inconsistent with R2.3, because R2.3.2 allows interruption of other network customers under certain conditions. It would seem to be better to place the superscript 2 at the end of R2.3.1 rather than at the end of R2.3, in both FAC-010 and FAC-011.
Pepco Holdings, Inc.		x	The proposed footnote, if it is to be used, should be appled to R2.3.1 only and not to R2.3 in general. The wording of the proposed footnote limits the interruption of electric supply to the load directly served by the elements that are removed from service by the single contingency. The footnote is silent on "affected area" load. In order to clarify R2.3.1 would be better to eliminate the proposed footnote and modify R2.3.1 with the following: R2.3.1 Planned or controlled interruption of electric supply to radial customersor or some local network customers load that is directly served by the elements that are removed from service as result of the contingency.
PJM Interconnection		x	Since the term consequential load is used in other standards, this definition should be added to the NERC Glossary. This should be left up to the standard drafting team and consensus of industry comments.
ComEd Transmission Planning	x		
FRCC Compliance Committee	x		
Hydro One Networks, Inc.	x		
Hydro-Québec/TransÉnergie	x		
Independent Electricity SO	x		
IRC Standards Review Committee	x		
Midwest Reliability Organization	x		
NPCC Regional Standards Cmte.	x		
Oncor Electric Delivery	x		

#2 – Commenter	Yes	No	Comment
PSC of South Carolina	x		
SPP Operating Reliability WG	x		

3. Do you agree with the drafting team's removal of the phrase "e.g., load greater than studied?"

Summary Consideration: Most commenters agreed with the drafting team's removal of the phrase, "load greater than studied." Some commenters suggested that the existing requirement was confusing, and the drafting team modified the phrasing of the requirement to clarify the intent. The revision from the last approved version of the standard is shown below:

> **R2.3.2** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies, ~~e.g., load greater than studied~~.

#3 – Commenter	Yes	No	Comment
American Transmission Company		x	The SAR should explain the consequence of deleting the language from requirement 2.3.2. The language in question provides an example for Requirement 2.3.2. How should the statement "...if the real-time operating conditions are more adverse than anticipated in the corresponding studies" be interpreted if it is not load greater than studied? As a Transmission Owner and Operator we are not responsible for load forecasting but we use the load forecasting provided to us for our studies. Is anyone in violation of this Standard if the load forecasted is lower than the actual operating conditions? The SDT should confirm that this standard dictates what has to be included in a methodology and that it does not dictate how in real-time a Transmission Operator is to act to control to their SOLs/IROLs. This confirmation is needed because other NERC standards address what the Transmission Operator has to do in real-time and that this standard is not one of them.
Response: The system configuration in real-time wasn't the same as it was when the studies were conducted. There are no requirements in the standard for load forecasting, hence there can't be a violation of this standard related to load forecasting. There are no real-time requirements in FAC-010 or FAC-011.			
Midwest ISO		x	I agree with the drafting teams removal of the phrase "e.g., load greater than studied". However, the drafting team should delineate between the contingency conditions from the system conditions. The separate system conditions are the reason to adjust generation and not the previously

#3 – Commenter	Yes	No	Comment
			discussed contingency; therefore, the separate system conditions should be emphasize so that there is no missunderstanding.
Response: For clarification purposes, the drafting team added an "(a)" and added a "(b)" to the subrequirement.			
Midwest Reliability Organization		x	The MRO agrees with the drafting teams removal of the phrase "e.g., load greater than studied"; however, the drafting team should further clairify the subrequirement. The MRO finds the use of 'or' in the subrequirement to be very confusing. The MRO also would like clairification on 'Prior Outage'.
Response: For clarification purposes, the drafting team added an "(a)" and added a "(b)" to the subrequirement.			
PJM Interconnection		x	Removing this example would make the standard less clear but this removal does not change the intent. This should be left up to the standard drafting team and consensus of industry comments.
Response: Agree			
British Columbia Transm. Corp.	x		
CenterPoint Energy	x		
Dominion Virginia Power	x		
Duke Energy	x		
ComEd Transmission Planning	x		
FirstEnergy Corp.	x		
FRCC Compliance Committee	x		
Hydro One Networks, Inc.	x		
Hydro-Québec/TransÉnergie	x		
Independent Electricity SO	x		
IRC Standards Review Committee	x		
Manitoba Hydro	x		
NPCC Regional Standards Cmte.	x		
Oncor Electric Delivery	x		
Pepco Holdings, Inc.	x		
PSC of South Carolina	x		
SPP Operating Reliability WG	x		

4. Do you agree with the drafting team's withdrawal of the definition for "Cascading Outage" and the resultant use of the defined term, "Cascading" in the revised standards?

Summary Consideration: Most commenters agreed with the withdrawal of the definition for "Cascading Outage" – several commenters suggested that the revised standard should omit the word, "outage" from 2.2 in both FAC-010 and FAC-011 and the drafting team has done that.

#4 – Commenter	Yes	No	Comment
British Columbia Transm. Corp.		x	The word "outage" following "Cascading" can also be deleted. It is redundant with respect to the definition of Cascading.
Response: Agreed. The drafting team made this change to both FAC-010 and FC-011 R2.2.			
ComEd Transmission Planning		x	In both standards, FAC-010 and FAC-011, in section R2.2 the following wording change is required: "and Cascading (delete the word "outages") or uncontrolled separation shall not occur."
Response: Agreed. The drafting team made this change to both FAC-010 and FC-011 R2.2.			
Midwest ISO		x	Should text "(or condition)" be added to the Cascading definition listed in the SAR. Plus, where is the cascading definition in the NERC FAC-010-2 standard? I don't see this definition listed in the NERC FAC-010-2 standard.
Response: Because the definition of "Cascading" is already in the approved NERC Glossary of Reliability Terms, it was not included as a new definition in the proposed revisions to FAC-010 and FAC-011.			
Omaha Public Power District		x	Withdrawal of the definition for Cascading Outage is acceptable, but the manner in which FAC-010 and FAC-011 were revised makes for awkward reading, because the approved definition of Cascading treats the term Cascading as a noun, while the revised versions of FAC-010 and FAC-011 use the term as an adjective (modifying the word outages). It would seem to be more proper grammatically, in FAC-010 and FAC-011, to replace the words Cascading Outages by just the word Cascading (i.e., striking the word Outages).
Response: Agreed. The drafting team made this change to both FAC-010 and FC-011 R2.2.			
Manitoba Hydro	x		The approved definition of cascading is clear. The word "outages' could be removed from the standards without changing the understanding.
Response: Agreed. The drafting team made this change to both FAC-010 and FC-011 R2.2.			
PJM Interconnection	x		The proposed use of Cascading adequately covers the intent of the Standard.
Response: Thank you for your affirmative response.			

#4 – Commenter	Yes	No	Comment
American Transmission Company	x		
CenterPoint Energy	x		
Dominion Virginia Power	x		
Duke Energy	x		
FirstEnergy Corp.	x		
FRCC Compliance Committee	x		
Hydro One Networks, Inc.	x		
Hydro-Québec/TransÉnergie	x		
Independent Electricity SO	x		
IRC Standards Review Committee	x		
Midwest Reliability Organization	x		
NPCC Regional Standards Cmte.	x		
Oncor Electric Delivery	x		
Pepco Holdings, Inc.	x		
PSC of South Carolina	x		
SPP Operating Reliability WG	x		

5. If you have any other comments on the SAR or the proposed changes to comply with FERC Order 705, please provide them here.

#5 – Commenter	Comment
American Transmission Company	Issue 1: ATC interprets that changing its SOL methodology to be compliant with a new FAC-010 standard and establishing new SOLs to be compliant with the FAC-014-1 standard is separate from being compliant with the existing TPL-002-0 standard. The new FAC-010 may lead to the identification of new system operating limit violations, but compliance with TPL-002-0 still depends on dealing with the existing system performance limit violations specified in TPL-002-0. Therefore, mandatory compliance with FAC-010-2 would involve rewording the SOL methodology by 7/1/2008 to reflect the requirements in the standard. Mandatory compliance with FAC-014-1 by 1/1/2009 would involve recalculating and communicating any revised SOLs based on any changes that were made to the planning horizon SOL methodology. Mandatory compliance with TPL-002-0 would continue involve meeting the system performance requirements specified in this standard, until the standard is changed. Issue 2: The SDT should explain why the numbering of Requirement 2.4 in FAC-011-1 and Requirement 2.3.3 in FAC-010-1 are different? Both of these two requirement contain exactly the same language but in FAC-010 is a sub-requirement of R2.3 and in FAC-011 it a sub-requirement of R2.
Response: The drafting team does not see the "issue" identified in Issue 1. The implementation plan for FAC-010 and FAC-011 was not dependent on any changes made to the TPL standards. Entities are expected to comply with all applicable, approved, effective requirements. **Issue 2 –** The two sub-requirements highlighted are not intentionally different. We modified FAC-010 so that the subrequirement has the same weight as in FAC-011.	
Duke Energy	Standards TPL-001-0 through TPL-004-0 are being rewritten and consolidated into a new TPL-001-1. FAC-010-2 requirements R2.4 and R2.5 contain references to TPL-003, which will necessitate conforming changes to FAC-010-2 when TPL-001-1 is approved.
Response: When the TPL standards are revised, as envisioned, there will be conforming changes made to the FAC standards and to the ATC-related set of standards.	
FirstEnergy Corp.	We suggest adding the Violation Risk Factors (VRF) to the text of each requirement in each standard [Note, this should also include adding the VRFs to FAC-014-1].

#5 – Commenter	Comment
Response: The Commission directed NERC to modify some of the VRFs, and the filing to comply with this order has not been completed. VRFs will be added at a later date, once the entire set has been approved by the Board of Trustees and FERC.	
FRCC Compliance Committee	The Compliance Monitoring Responsibility should be the Regional Entity, not the Regional Reliability Organization. The RE's have the authority through their approved Delegation Agreements.
Response: Agreed. This is a modification that took place following the development of these standards.	
IRC Standards Review Committee	The ISO RTO Council has filed a Request for Clarification or in the alternative Rehearing. We ask the NERC SDT to consider any further clarifiying language FERC requests if they impact FAC-010 and FAC-011. Regarding Footnote (1) on both FAC-010 & 011 - there is no apparent reason to include Footnote (1) as it is editorial, it is not a requirement and it adds no additional clarity. The Requirements already identify what must be studied - which is the purpose of the standard.
Response: If the Commission agrees with the ISO RTO Council, then it may issue another Order directing NERC to make additional changes to the standards. At this time, the drafting team does not know when the Commission will respond to the ISO RTO Council's request for a rehearing – and the drafting team is trying to get the already identified modifications to the standards implemented before the first of these standards becomes effective on July 1, 2008.	
Manitoba Hydro	MH does not see a reliability need to define SOLs in the planning horizon and believes the Standard FAC-010-1 should be withdrawn. Operators do not use future SOLs, so who benefits from the extra work required to comply with this SAR?
Response: Stakeholders indicated a desire to require entities to have a methodology for determining SOLs for use in the planning horizon.	
Midwest ISO	Yes, In the brief description section of the SAR (page SAR-2). The violation Risk Factors are suggested to be updated in accordance with FERC order 750. Isn't this FERC order 705? The VSL drafting team did not create VSLs for these two standards. Thus, creation of VSLs should be added to the scope of this SAR.
Response: You are correct – the Order is "705", not "750." This has been corrected.	
Midwest Reliability Organization	Yes, In the brief description section of the SAR (page SAR-2). The Violation Risk Factors are suggested to be updated in accordance with FERC order 750, should be FERC Order 705.
Response: You are correct – the Order is "705", not "750." This has been corrected.	
PJM Interconnection	Revision of the standards should be left up to the standard drafting team and consensus

#5 – Commenter	Comment
	of industry comments.
Response: NERC has an obligation to comply with the Commission's directives.	

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Standard Authorization Request Form

Title of Proposed Standard	Modifications to FAC-010-1, FAC-011-1, and FAC-014-1
Request Date	January 11, 2008
Modified Data	March 31, 2008

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Paul Johnson for Facility Ratings SDT	☐	New Standard
Primary Contact	Paul Johnson	☒	Revision to existing Standard FAC-010-1 — System Operating Limits Methodology for the Planning Horizon FAC-011-1 — System Operating Limits Methodology for the Operations Horizon FAC-014-1 — Establish and Communicate System Operating Limits
Telephone Fax	614-716-6690	☐	Withdrawal of existing Standard
E-mail	pbjohnson@aep.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) The revisions are needed to eliminate the ambiguity identified by FERC in the approved standards and in the definition of Cascading Outage.
Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.) The regulatory approved version of FAC-010-1 will become effective on July 1, 2008 and set of the clarifications should be made before that time.
Brief Description (Provide a paragraph that describes the scope of this standard action.) In FERC Order 705, the Commission directed NERC to make the following modifications:

FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied” In addition, the Commission remanded the definition of “Cascading Outage” and this term should be withdrawn from the NERC Glossary of Reliability Terms. “Levels of Non-compliance” should be removed and replaced with new “Violation Severity Levels”.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) In FERC Order 705, the Commission directed NERC to make the following modifications: ▪ FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied” In addition, the Commission remanded the definition of “Cascading Outage” and this term should be retired from the NERC Glossary of Terms Used in Reliability Standards, and the standards should be updated to use the defined term, “Cascading”. The “Levels of Non-compliance” should be removed and replaced with new “Violation Severity Levels”.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Authority	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	The Regional Variances within FAC-010 and FAC-011 need to be updated to include Violation Severity Levels to comply with FERC Order 705.

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Standard Authorization Request Form

Title of Proposed Standard	Modifications to FAC-010-1, ~~and~~ FAC-011-1, and FAC-014-1
Request Date	January 11, 2008
Modified Data	March 31, 2008

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Paul Johnson for Facility Ratings SDT	☐	New Standard
Primary Contact	Paul Johnson	☒	Revision to existing Standard FAC-010-1 — System Operating Limits Methodology for the Planning Horizon FAC-011-1 — System Operating Limits Methodology for the Operations Horizon FAC-014-1 — Establish and Communicate System Operating Limits
Telephone Fax	614-716-6690	☐	Withdrawal of existing Standard
E-mail	pbjohnson@aep.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The revisions are needed to eliminate the ambiguity identified by FERC in the approved standards and in the definition of Cascading Outage.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The regulatory approved version of FAC-010-1 will become effective on July 1, 2008 and set of the clarifications should be made before that time.

Brief Description (Provide a paragraph that describes the scope of this standard action.)
In FERC Order 705, the Commission directed NERC to make the following modifications:

~~FAC-010-1 Requirement R2.3 — clarify what is meant by the term, "consequential load"~~ ~~FAC-011-1 Requirement R2.3 — clarify what is meant by the term, "consequential load"~~ FAC-011-1 Requirement R2.3.2 – eliminate the phrase, "load greater than studied" In addition, the Commission remanded the definition of "Cascading Outage" and this term should be withdrawn from the NERC Glossary of Reliability Terms. "Levels of Non-compliance" should be removed and replaced with ~~the~~ new "Violation Severity Levels" ~~developed by the VSL Drafting Team, once those VSLs are approved by their Ballot Body~~. ~~Update the standard to include the VRFs that were approved or modified in accordance with FERC Order 750.~~
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) In FERC Order 705, the Commission directed NERC to make the following modifications: ~~▪FAC-010-1 Requirement R2.3 — clarify what is meant by the term, "consequential load"~~ ~~▪FAC-011-1 Requirement R2.3 — clarify what is meant by the term, "consequential load"~~ ▪ FAC-011-1 Requirement R2.3.2 – eliminate the phrase, "load greater than studied" In addition, the Commission remanded the definition of "Cascading Outage" and this term should be retired from the NERC Glossary of Terms Used in Reliability Standards, and the standards should be updated to use the defined term, "Cascading". The "Levels of Non-compliance" should be removed and replaced with ~~the~~ new "Violation Severity Levels" ~~developed by the VSL Drafting Team, once those VSLs are approved by their Ballot Body~~.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Authority	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
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☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	The Regional Variances within FAC-010 and FAC-011 need to be updated to include Violation Severity Levels to comply with FERC Order 705.

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Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Proposed Action Plan and Description of Current Draft:

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2.

3. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

3.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

4. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of three or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One or the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading o does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading o does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

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Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** ~~July 1, 2007~~July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

~~R2.3.3.~~R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

~~R2.4.~~R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

~~R2.5.~~R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

~~R2.5.1.~~R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. ~~Violation Severity Levels (To be added once approved by the VSL Ballot Pool)~~

~~3.Levels of Non-Compliance (Does not apply to the Western Interconnection)~~

~~**3.1.Level 1:** There shall be a level one non-compliance if either of the following conditions exists:~~

~~**3.1.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~**3.1.2**No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~**3.2.Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.~~

~~**3.3.Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~**3.3.1**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~**3.3.2**The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the six required topics in R3.~~

~~**3.4.Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.~~

3. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

4. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of three or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One or the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading o~~Outages~~ does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading o~~Outages~~ does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

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None:

A. Introduction

1. Title: **System Operating Limits Methodology for the Operations Horizon**

2. Number: FAC-011-2

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Reliability Coordinator

5. Effective Date: October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator’s SOL Methodology does not require that SOLs are set to meet BES performance in either the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through

				R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One or the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR

			methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to

			Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010 and FAC-011

Standard Development Roadmap

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6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, ~~2007~~2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable[2]:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or~~,~~ (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

~~[2] The interruption of electric supply is limited to the load that is directly served by the elements that are removed from service as a result of the contingency.~~

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

~~**2. Violation Severity Levels (To be added once approved by the VSL Ballot Pool)**~~

~~**3. Levels of Non-Compliance (Does not apply to the Western Interconnection)**~~

~~**3.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:~~

~~**3.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~**3.1.2** No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~**3.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.~~

~~**3.3. Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~**3.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~**3.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the seven required topics in R3.~~

~~**3.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.~~

~~3~~.2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

~~3.1.~~2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

~~3.1.1~~2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

~~3.1.2~~2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

~~3.2.~~2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

~~3.3.~~2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

~~3.3.1~~2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

~~3.3.2~~2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

~~3.3.3~~2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

~~3.4.~~2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

~~4.~~3. Violation Severity Levels:

R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in either the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through

				R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One or the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR

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R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to

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1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

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1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~Outages~~ ~~outages~~ does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

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Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

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None.

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1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are Sols for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Proposed Action Plan and Description of Current Draft:

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, ~~2008~~2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

~~**2.Levels of Non-Compliance**~~

~~**2.1.Level 1:** Not applicable.~~

~~**2.2.Level 2:** Not all SOLs were provided in accordance with their respective schedules.~~

~~**2.3.Level 3:** SOLs provided were not developed consistent with the SOL Methodology.~~

~~**2.4.Level 4:** There shall be a level four non-compliance if either of the following conditions exist:~~

~~**2.4.1**No SOLs were provided in accordance with their respective schedules.~~

~~No evidence the Planning Authority delivered a set of stability-related multiple contingencies and their associated limits to Reliability Coordinators in accordance with R6.~~

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLsfor the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

~~E.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Opens
March 31–April 29, 2008

http://www.nerc.com/~filez/standards/Facility_Ratings_Project_2008-04.html

A revised SAR for Project 2008-04 and proposed changes to the following standards are all posted for a 30-day comment period from March 31–April 29, 2008.

FAC-010-1 — System Operating Limits Methodology for the Planning Horizon
FAC-011-1 — System Operating Limits Methodology for the Operations Horizon
FAC-014-1 — Establish and Communicate System Operating Limits

In Order 705, FERC approved these three standards, and directed NERC to make changes to each of these standards. The changes fall into two categories — those that are subject to stakeholder input and those that are not subject to stakeholder input. The changes proposed are limited to addressing the directives in Order 705 that are subject to stakeholder input — retiring a definition; removing an example from a requirement; and adding Violation Severity Levels.

Please use this comment form to submit comments on this SAR and the conforming changes to the standards.

http://www.nerc.com/~filez/standards/Facility_Ratings_Project_2008-04.html

Please use only the electronic form to submit comments by **April 29, 2008**. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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RELIABILITY CORPORATION

Implementation Plan
FAC-010-2, FAC-011-2, and FAC-014-2

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards

FAC-010-1, FAC-011-1, and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards

Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date

The proposed effective dates are the same for all regulatory jurisdictions:

- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008
- FAC-014-2 will become effective on January 1, 2009

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan
FAC-010-2, ~~and~~ FAC-011-2, and FAC-014-2

Implementation Plan for FAC-010-2, ~~and~~ FAC-011-2 and FAC-014

FAC-010-1 — System Operating Limits Methodology for the Planning Horizon
FAC-011-1 — System Operating Limits Methodology for the Operations Horizon
FAC-014-1 — Establish and Communicate System Operating Limits

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards
FAC-010-1, ~~and~~ FAC-011-1, and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards
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Proposed Effective Date
The proposed effective dates are the same for all regulatory jurisdictions:

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- FAC-014-2 will become effective on January 1, 2009

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Comment Form for Project 2008-04

Current Survey Language English

Responses have already been collected for this survey. Making changes to questions, such as by deleting options and/or removing matrix rows or columns could cause existing answers to be deleted.

Survey Manager Survey Editor Properties Style Permissions Activation Languages Test Survey

New Page Preview Print Export View All Pages

Hidden Items

Add Item | Branching

Branching Rules:
No branching rules.

This page does not contain any items.

Page 1

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

The Facility Ratings SAR Drafting Team would like to receive industry comments on this SAR for modifications to FAC standards 010, 011, and 014. Accordingly, we request that you include your comments on this form and submit them by **April 29, 2008**.

If you experience any difficulty using this form, please contact Barbara Bogenrief at 609-452-8060.

Background Information:

The drafting team working on the revisions to FAC-010, FAC-011, and FAC-014 to comply with FERC Order 705 made two changes to the SAR and associated standards in response to stakeholder comments.

- The SAR was modified to include the development of Violation Severity Levels. When the SAR was originally developed, the requesters thought the VSL drafting team was developing VSLs for these standards, and have since discovered that the VSL drafting team did not develop VSLs for FAC-010, FAC-011, and FAC-014.
- The SAR was also modified to remove references to clarifying what is meant by "consequential loss of load." This is being addressed by another drafting team.

Please review the changes to the SAR and standards, and then answer the following questions. Please submit your responses no later than **April 29, 2008**.

Conditions: There are NO conditions. This item will always be displayed.

Page 2

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
If '2.1 Individual or group.' Is Equal To 'Individual' then go to page 3
If '2.1 Individual or group.' Is Equal To 'Group' then go to page 4

Item 1 [Radio Buttons] Edit | Move | Copy | Insert | Export | Delete

***Individual or group.**

- ○ Individual
- ○ Group

Conditions: There are NO conditions. This item will always be displayed.

Page 3

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
If '2.1 Individual or group.' Is Equal To 'Individual' then go to page 5

Item 1 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

*Name

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

*Organization

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

*Telephone
(###) ###-####

Conditions: There are NO conditions. This item will always be displayed.

Item 4 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

*E-mail

Conditions: There are NO conditions. This item will always be displayed.

Item 5 [Checkboxes] Edit | Move | Copy | Insert | Export | Delete

*NERC Region (check all Regions in which your company operates)

- [ ] ERCOT
- [ ] FRCC
- [ ] MRO
- [ ] NPCC
- [ ] RFC
- [ ] SERC
- [ ] SPP
- [ ] WECC
- [ ] NA - Not Applicable

Conditions: There are NO conditions. This item will always be displayed.

Item 6 [Checkboxes] Edit | Move | Copy | Insert | Export | Delete

*Registered Ballot body segment (check all industry segments in which your company is registered)

- [ ] 1 - Transmission Owners
- [ ] 2 - RTOs and ISOs
- [ ] 3 - Load-serving Entities
- [ ] 4 - Transmission-dependent Utilities
- [ ] 5 - Electric Generators
- [ ] 6 - Electicity Brokers, Aggregators
- [ ] 7 - Large Electricity End Users
- [ ] 8 - Small End Users

- [ ] 9 - Federal, State, Provincial Regulatory, or other Government Entities
- [ ] 10- Regional Reliabiity Organizations/Regional Entities
- [ ] Not Applicable

Conditions: There are NO conditions. This item will always be displayed.

Page 4

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
If '2.1 Individual or group.' Is Equal To 'Group' then go to page 5

Item 1 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

***Group Name**

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

***Lead Contact**

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

***Contact Organization**

Conditions: There are NO conditions. This item will always be displayed.

Item 4 [Checkboxes] Edit | Move | Copy | Insert | Export | Delete

Registered Ballot body segment (check all applicable industry segments)

- [ ] 1 - Transmission Owners
- [ ] 2 - RTOs and ISOs
- [ ] 3 - Load-serving Entities
- [ ] 4 - Transmission-dependent Utilities
- [ ] 5 - Electric Generators
- [ ] 6 - Electicity Brokers, Aggregators
- [ ] 7 - Large Electricity End Users
- [ ] 8 - Small End Users
- [ ] 9 - Federal, State, Provincial Regulatory, or other Government Entities
- [ ] 10 - Regional Reliability Organizations/Regional Entities
- [ ] N/A

Conditions: There are NO conditions. This item will always be displayed.

Item 5 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

***Contact Telephone**
(###) ###-####

Conditions: There are NO conditions. This item will always be displayed.

Item 6 [Open-Ended Single-Line Text] Edit | Move | Copy | Insert | Export | Delete

***Contact E-mail**

Conditions: There are NO conditions. This item will always be displayed.

Item 7 [Matrix] Edit | Move | Copy | Insert | Export | Delete

Please complete the following information.

	Additional Member	Additional Organization	Region	Segment Selection 1	2	3	4	5	6	7	8	9	10	NA
1.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
2.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
3.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
4.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
5.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
6.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
7.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
8.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
9.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
10.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
11.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
12.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
13.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
14.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
15.			Select:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Conditions: There are NO conditions. This item will always be displayed.

Page 5

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

Several stakeholders indicated that the Assess Transmission Future Needs SDT working on revisions to the "TPL" series of standards has proposed a NERC definition of "Consequential Load Loss." Because Order 705 did not direct NERC to include this footnote in FAC-010 and FAC-011, and because NERC has already made a commitment to modify the ATC related standards and the FAC related standards to align with the TPL standards when they are revised, the drafting team has elected to remove the footnote from the revised standards.

Do you agree with this change?

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Radio Buttons] Edit | Move | Copy | Insert | Export | Delete

Question 1:

◯ Yes

◯ No

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Multi-Line Text] Edit | Move | Copy | Insert | Export | Delete

Question 1 Comments:

Conditions: There are NO conditions. This item will always be displayed.

Page 6 Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

Do you agree with the Violation Severity Levels proposed for FAC-010?

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Radio Buttons] Edit | Move | Copy | Insert | Export | Delete

Question 2:

- Yes
- No

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Multi-Line Text] Edit | Move | Copy | Insert | Export | Delete

Question 2 Comments:

Conditions: There are NO conditions. This item will always be displayed.

Page 7 Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

Do you agree with the Violation Severity Levels proposed for FAC-011

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Radio Buttons] Edit | Move | Copy | Insert | Export | Delete

Question 3:

- Yes
- No

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Multi-Line Text] Edit | Move | Copy | Insert | Export | Delete

Question 3 Comments:

Conditions: There are NO conditions. This item will always be displayed.

Page 8

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

Do you agree with the Violation Severity Levels proposed for FAC-014?

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Radio Buttons] Edit | Move | Copy | Insert | Export | Delete

Question 4:

- Yes
- No

Conditions: There are NO conditions. This item will always be displayed.

Item 3 [Open-Ended Multi-Line Text] Edit | Move | Copy | Insert | Export | Delete

Question 4 Comments:

Conditions: There are NO conditions. This item will always be displayed.

Page 9

Add Item | Copy | Move | Delete | Conditions | Branching

Page Conditions:
No conditions.

Branching Rules:
No branching rules.

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

If you have any other comments on the revised SAR or standards that you haven't already made in response to the first four questions, please provide them here.

Conditions: There are NO conditions. This item will always be displayed.

Item 2 [Open-Ended Multi-Line Text] Edit | Move | Copy | Insert | Export | Delete

Question 5 Comments:

Conditions: There are NO conditions. This item will always be displayed.

Page 10

Add Item | Copy | Move | Delete | Conditions

Page Conditions:
No conditions.

Item 1 [Response Summary] Edit | Move | Copy | Insert | Export | Delete

(User Survey Response)

Conditions: There are NO conditions. This item will always be displayed.

Completion Events

Add Item

Item 1 [HTML] Edit | Move | Copy | Insert | Export | Delete

Thank you for completing the comment form for Project 2008-04.

Conditions: There are NO conditions. This item will always be displayed.

Project 2008-04 Modifications to FAC Standards to Comply with Order 705

Background Information:

The drafting team working on the revisions to FAC-010, FAC-011, and FAC-014 to comply with FERC Order 705 made two changes to the SAR and associated standards in response to stakeholder comments.

- The SAR was modified to include the development of Violation Severity Levels. When the SAR was originally developed, the requesters thought the VSL drafting team was developing VSLs for these standards, and have since discovered that the VSL drafting team did not develop VSLs for FAC-010, FAC-011, and FAC-014.
- The SAR was also modified to remove references to clarifying what is meant by "consequential loss of load." This is being addressed by another drafting team.

Please review the changes to the SAR and standards, and then answer the following questions. Please submit your responses no later than **April 29, 2008.**

1. Several stakeholders indicated that the Assess Transmission Future Needs SDT working on revisions to the "TPL" series of standards has proposed a NERC definition of "Consequential Load Loss." Because Order 705 did not direct NERC to include this footnote in FAC-010 and FAC-011, and because NERC has already made a commitment to modify the ATC related standards and the FAC related standards to align with the TPL standards when they are revised, the drafting team has elected to remove the footnote from the revised standards. Do you agree with this change?

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree with the Violation Severity Levels proposed for FAC-010?

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the Violation Severity Levels proposed for FAC-011?

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the Violation Severity Levels proposed for FAC-014?

   ☐ Yes

   ☐ No

   Comments:

5. If you have any other comments on the revised SAR or standards that you haven't already made in response to the first four questions, please provide them here.

   Comments:

Comments on Second Posting of SAR and FAC-010-2, FAC-011-2, FAC-014-2 for Order 705

This SAR and associated standards were posted for a 30-day public comment period from March 31 through April 29, 2008. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were 13 sets of comments, including comments from more than 60 different people from more than 45 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

		Industry Segments									
Commenter	**Company**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Anita Lee	AESO		x								
John Sullivan (G3)	Ameren	x									
Jason Shaver	ATC	x									
Chris Bradley (G2)	Big Rivers Electric Cooperative	x		x							
Brent Kinsford	CAISO		x								
Danny McDaniel (G4)	CLECO	x		x		x					
Ed Thompson (G1)	Consolidated Edison Co. of New York	x									
Michael Gildea (G1)	Constellation Energy						x				
Ron Hart (G1)	Dominion Resources, Inc.					x					
Jack Kerr (G2)	Dominion Virginia Power			x		x	x				
Louis Slade (G2)	Dominion Virginia Power										
Greg Rowland (G2)	Duke Energy - Carolinas	x		x							
Brian Berkstresser (G4)	Empire District Electric	x		x		x					
Ed Davis	Entergy	x									
Steve Myers	ERCOT										x
Dave Folk	FirstEnergy	x		x		x	x				
Doug Hohlbaugh	FirstEnergy	x		x		x	x				
Sam Ciccone	FirstEnergy	x		x		x	x				
Wayne Pourciau (G2)	Georgia System Operations Corp.	x		x							
Ross Kovacs (G2)	Georgia Transmission Corp.	x									
David Kiguel (G1) (I)	Hydro One Networks, Inc.	x									
Roger Champagne (G1)	Hydro-Quebec TransEnergie		x								
Sylvain Clermont (G1)	Hydro-Quebec Trans-Energie	x									
Ron Falsetti (G5) (G1)	Independent Electricity System Operator		x								
Kathleen Goodman (G1)	ISO - New England		x								
Matt Goldbery	ISO-NE		x								
Mike Gammon (G4)	Kansas City Power and Light	x		x		x					
Dan Jewell (G2)	Louisiana Generating, LLC	x		x	x						

Commenter	Company	Industry Segments									
		1	2	3	4	5	6	7	8	9	10
Don Nelson (G1)	Massachusetts Dept. of Public Utilities									x	
Scott Goodwin (G2) (G3)	Midwest ISO		x								
Bill Phillips	MISO		x								
Nabil Hitti (G1)	National Grid				x						
Michael Schiavone (G1)	National Grid US	x									
Randy MacDonald (G1)	New Brunswick System Operator		x								
William DeVries (G1)	New York Independent System Operator		x								
Ralph Rufrano (G1)	New York Power Authority	x									
Guy Zito (G1)	NPCC										x
Lee Pedowicz (G1)	NPCC										x
Jim Castle	NYISO		x								
Don Hargrove (G4)	Oklahoma Gas & Electric	x		x		x					
John Mayhan	OPPD	x									
Patrick Brown	PJM		x								
Mike Bryson (G2)	PJM Interconnection		x								
Rick White	Northeast Utilities	x									
Sara McCoy	Salt River Project	x		x		x	x				
Phil Kleckley (G3)	SC Electric and Gas			x							
Carter Edge (G2)	SERC										x
John Troha (G2)	SERC										x
Pat Huntley (G3)	SERC										x
Jim Griffith (G2)	Southern Company	x		x							
Marc Butts (G2)	Southern Company	x		x							
Bob Jones (G3)	Southern Company Services	x									
Jason Smith (G4)	Southwest Power Pool										x
Robert Rhodes (G4)	Southwest Power Pool										x
Charles Yeung	Southwest Power Pool										x
Kyle McMenamin (G4)	Southwestern Public Service	x		x		x					
Donald Drum (G2)	Tennessee Valley Authority	x		x						x	
Joel Wise (G2)	Tennessee Valley	x		x						x	

Commenter	Company	Industry Segments									
		1	2	3	4	5	6	7	8	9	10
	Authority										
Travis Sykes (G3)	Tennessee Valley Authority	x									
Walter Joly (G2)	Tennessee Valley Authority	x		x						x	
Allen Klassen (G4)	Westar Energy	x		x		x					

Legend:
G1 – NPCC Regional Standards Committee, RSC
G2 – SERC OC Standards Review Group
G3 - SERC EC Planning Standards Subcommittee
G4 - SPP Operating Reliability Working Group
G5 - IRC Standards Review Committee

I – indicates this person submitted individual comments in addition to the identified group comments

Question 1 – Several stakeholders indicated that the Assess Transmission Future Needs SDT working on revisions to the "TPL" series of standards has proposed a NERC definition of "Consequential Load Loss." Because Order 705 did not direct NERC to include this footnote in FAC-010 and FAC-011, and because NERC has already made a commitment to modify the ATC-related standards to align with the TPL standards when they are revised, the drafting team has elected to remove the footnote from the revised standards. Do you agree with this change?

Entergy	No	We suggest the TPL series of standards and these FC standards should be properly aligned at the appropriate time.
NPCC RSC	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
Northeast Utilities	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
IESO	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
IRS SRC	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
SERC EC PSS	Yes	Please remove the reference to footnote in R2.3 in FAC-010 and 011.
FirstEnergy	Yes	The standards as proposed still show the superscript no. 2 for this removed footnote in R2.3.
OPPD	Yes	However, in both FAC-010 and FAC-011, the superscript "2" at the end of R2.3 needs to be removed.
ATC	Yes	ATC agrees with this decision.
Hydro One Networks, Inc.	Yes	
SERC OC SRG	Yes	

SPP ORWG	Yes	

Question 2 - Do you agree with the Violation Severity Levels proposed for FAC-010?

NPCC Regional Standards Committee, RSC	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe. R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs. R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
SERC OC Standards Review Group	No	The "Severe" Violation Severity Level for R3 overlaps the "High" Violation Severity Level. The word "three" should be replaced with "four" to prevent this overlap, i.e., The Planning Authority has a methodology for determining SOLs that is missing a description of "four" or more of the following: R3.1 through R3.6Under the "Moderate" Violation Severity Level for R4 (first line), the word "or" should be changed to "of".
SERC EC Planning Standards Subcommittee	Yes	The VSL for R4 should read "One of the following."
SPP Operating Reliability Working Group	No	We find it difficult to determine which of the subrequirements is more critical than the other in R1. Therefore we suggest the SDT change the VSLs to something like the following: The Planning Authority has a documented SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Finally, substitute three subrequirements for one and assign a Higher category.We would suggest removing the first paragraph (above the 'or') in the Severe category. For R2, we suggest rewording the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another.The Severe VSL for R3 should be changed to read '?four or more of the following:' The VSLs for R4 add an additional requirement to R4 by stipulating a specific time reference for the requirement. We would suggest eliminating the timing aspects and revise the VSLs to parallel what

		we proposed for the VSLs for R1. For R5, delete the phrase '?but less than 60 calendar days.' from the Lower VSL. We would suggest the following language for the Moderate category: 'The Planning Authority in their response did not include statements regarding changes or no changes to their SOL methodology.' Delete the first paragraph (above the 'or') of the VSL in the Higher category and keep the second paragraph (below the 'or'). Change the Severe category to the following: 'The Planning Authority failed to respond.'
Northeast Utilities	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe. R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Ontario IESO	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe.R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
IRC Standards Review Committee	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL criteria guideline document, progressive (graded) VSLs should be made dependent on how many or the percentage of the sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe, etc.R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the

		determination of the progressive (graded) VSLs. We suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: We agree with these VSLs. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Entergy	No	We suggest the removal of the term "outage" from FAC-010-2 R2.2.
Hydro One Networks, Inc.	No	The VSLs for requirement R1 should weigh all violations of the 3 sub-requirements equally. For example, missing one of the three sub-requirements in the SOL methodology should result in a Medium VSL, missing two of three should result in a High VSL and missing all three should result in a Severe VSL and maintain having no SOL methodology as Severe. We agree with VSLs for requirements R2 and R3 however we find the VSL for R4 overly complex. We suggest HIGH: One of the following: (1)The Planning Authority failed to issue its SOL methodology and changes to that methodology to one of the required entities or (2) For a change in methodology, the changed methodology was issued after the effictiveness of the change but up to 30 calendar days after the effectiveness. SEVERE: One of the following: (1)The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than one of the required entities or (2) For a change in methodology, the changed methodology was issued 30 calendar days or more after the date of effectiveness of the change.
ATC	No	The ranking of the R1 levels should be lowered and the typographical error in R3 should be corrected. R1: Move omission of R1.2 (facility rating statement) from Moderate to Lower. Move omission of R1.3 (IROL description) from High to Moderate. Move omission of R1.1 (applicable to planning horizon SOLs) from Severe to High. Add omission of all three requirements to the Severe Level. R3: Correct typographical error in Severe Level text from “three or more” to “four or more”
FirstEnergy	Yes	

Question 3 – Do you agree with the Violation Severity Levels proposed for FAC-011?

NPCC Regional Standards Committee, RSC	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them. Mathematical methods can be applied to sub-requirements only if each sub-requirement is deemed to be of equal importance. If not, and the sub-requirements have different levels of importance, then some consideration should be given to the order in which they are employed in the mathematical formula.
Northeast Utilities	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them. Mathematical methods can be applied to sub-requirements only if each sub-requirement is deemed to be of equal importance. If not, and the sub-requirements have different levels of importance, then some consideration should be given to the order in which they are employed in the mathematical formula.
Ontario IESO	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them.
IRC Standards Review Committee	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive (graded) versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them.
SERC OC Standards Review Group	No	The headings for the Violation Severity Levels are missing from the table. Under the "Severe" Violation Severity Level for R2, the word "either" should be deleted from the sentence. Under the "Severe" Violation Severity Level for R4, the reference to "Planning Authority" should be replaced with "Reliability Coordinator".
SPP Operating Reliability Working	No	We again find it difficult to determine which of the subrequirements is more critical than the other in R1. Therefore we suggest the SDT change the VSLs to something like the following: The Reliability Coordinator has a documented SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a

Group		Moderate category. Finally, substitute three subrequirements for one and assign a Higher category.We would suggest removing the first paragraph (above the 'or') in the Severe category. For R2, we suggest rewording the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another.The Severe VSL should for R3 should be changed to read '?four or more of the following:' The VSLs for R4 add an additional requirement to R4 by stipulating a specific time reference for the requirement. We would suggest eliminating the timing aspects and revise the VSLs to parallel what we proposed for the VSLs for R1. Change the VSLs for R5 to match those we proposed in R5 of FAC-010 except replace Planning Authority with Reliability Coordinator
Entergy	No	Order 705 contains comments about removing the term "load greater than studied", or address FERC's concerns with the use of the term. It seems the term is still in the standard and we think FERC's concerns have not been addressed. Please remove the term or address FERC's concerns.
Hydro One Networks, Inc.	No	We agree with VSLs for requirements R1, R3 and R5 however we find the VSL for R4 overly complex. We suggest HIGH: One of the following: (1)The Reliability Coordinator failed to issue its SOL methodology and changes to that methodology to one of the required entities or (2) The Reliability Coordinator failed to issue its SOL methodology and changes to that methodology prior to the date of effectiveness but up to 2 days after the date of effectiveness. Here we suggest using 2 days as opposed to 30 days in FAC-010 because this is in the Operating Horizon and not the Planning Horizon. SEVERE: One of the following: (1)The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than one of the required entities or (2) The Reliability Coordinator issued its SOL methodology and changes to that methodology 3 days or more after the date of effectiveness. As well, in the Severe VSL for R2, it is not clear the use of the word "either". We suggest deleting this word.
ATC	No	VSL's for R4 FAC-011 requirement 4 specifies that the RC issue its SOL Methodology and changes to their methodology. Suggested Modification: Have only one VSL in the Moderate level that states the following: The RC did not issue its SOL Methodology or changes to its methodology to all required entities. We find our approach makes the VSLs for this requirement simpler to understand and determine.

		VSL's for R5 Requirement 5 specifies that the RC has to provide documented technical comments within 45 calendar days following receipt of comments. Suggested Modification: Have only one VSL in the lower level that states the following: The RC did not provide technical comments within 45 calendar days following receipt of comments.
FirstEnergy	Yes	

Question 4 – Do you agree with the Violation Severity Levels proposed for FAC-014?

NPCC Regional Standards Committee, RSC	No	(1) We applaud the SDT for developing progressive VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any criteria or guidleine on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor folks conduct a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report on compliance. Alternatively (not preferred), the requirement is viewed as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go through the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would consitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
SERC OC Standards Review Group	No	The language for identifying the ranges of inconsistency with the RC methodologies under each severity level for each of Requirements R1 - R4 is very confusing and misleading. There is no need to state that "there are SOLs"?. because this standard would not apply if there were none. We would suggest the following language for R1 VSLs and similar language for R2 - R4 VSLs: "Lower":

		Up to 25% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "Moderate" 26 to 50% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "High": 51 to 75% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "Severe": More than 75% of the SOLsidentified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1)For R3 and R4 under all VSLs, the "Planning Cooordinator" should be changed to the "Planning Authority". Under R4 for the "High" VSL, "Reliability Coordinator" should be changed to "Planning Authority".
SPP Operating Reliability Working Group	No	The VSLs for R5 introduce a specific timing requirement that is not included in R5. This should be deleted. We find it difficult to determine which of the subrequirements is more critical than the other in R5. Therefore we suggest the SDT change the VSLs to something like the following: The responsible entity has communicated its SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Substitute three subrequirements for one and assign a Higher category. Finally, substiture four subrequirements for one and assign a Severe category.In R6 we suggest moving the Higher category VSL to the empty Moderate category. Move the second paragraph of the Severe category to the Higher category. Leave the first paragraph of the Severe category as the only entry for the Severe category.
Northeast Utilities	No	(1) We applaud the SDT for developing progressive VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any criteria or guidleine on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor folks conduct a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report on compliance. Alternatively (not preferred), the requirement is viewed as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go through the

		identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would consitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
Ontario IESO	No	(1) We applaud the SDT for developing progressive VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any criteria or guidleine on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor folks conduct a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report on compliance. Alternatively (nor preferred), the requirement is viewed as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go throught the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would consitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found,

		as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
IRC Standards Review Committee	No	(1) We commend the SDT for developing progressive (graded) VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any guideline on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor conducts a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report compliance. Alternatively (not preferred), the requirement can be treated as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which of the sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go throught the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would constitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
Entergy	No	The Version History contains a note that "Cascading Outage" was changed to "Cascading". We suggest that note be removed since the change does not apply to this standard.

FirstEnergy	No	The following are potential issues with the VSL for FAC-014-1: 1. R5 - The VSL do not address situations when the entities do not provide the subset of SOLs that are also considerd potential IROLs. We suggest replacing the phrase "The responsible entity provided its SOLs" with "The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) throughout the R5 VSLs where appropriate. 2. General - The main requirement number (ex. R5) does not need to be shown in parenthesis after the text of the VSL since the VSL table is arranged based on the main requirements. This is only useful if the VSL is geared toward a specific subrequirement (ex. R5.1).
HydroOne Networks	No	For the VSLs for requirements R1, R2, R3 and R4 we suggest only High and Severe VSLs. Example, High: "There are SOLs for the Reliability Coordinator Area, but from 1% to 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology." Severe: "There are SOLs for the Reliability Coordinator Area, but more than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology." We suggest VSLs for R1, R2, R3 and R4 all follow the same pattern as the example provided. We find the VSLs for R5 to be well thought out but overly complex due to format of the requirement itself. We suggest breaking up the requirement into several requirements by isolating the responsible entity and their responsibilities. As well, for R6 we suggest a Severe VLS for violoation of the "parent" requriement R6 and a High VSLs for violation of either sub-requirement R6.1 and R6.2. Example: HIGH: One of the following: The Planning Authority identified a list of multiple continegnecies and associated stability limits, via studies, however the PA failed to provide thse to the RC that monitors the facilities asscoiated with those contingencies and limits. or (2) The Planning Authority, via studies, did not identify any stabilityrelated multiple contingencies, however the PA failed to notify the RC of this outcome. SEVERE: The Planning Authority did not conduct studies to indenify if a subset of multiple contingencies from the Standard TPL-003 result in stability limits.
ATC	No	VSL's for R5 Requirement 5 specifies that the RC, PA and TP provide its SOLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for

		delivery of those limits. Suggested Modification: Have only one VSL in the Moderate level that states the following: The RC, PA or TP did not provide its SOLs to those entities that have a reliability-related need for those limits per the schedule.
SERC EC Planning Standards Subcommittee	Yes	

Question 5 – If you have any other comments on the revised SAR or standards that you haven't already made in response to the first four questions, please provide them here.

NPCC Regional Standards Committee, RSC	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it.
Northeast Utilities	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it.
Ontario IESO	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it.
IRC Standards Review Committee	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it
Salt River Project	FAC-010-2 R2.2 and R2.5 use the capitalized word "Cascading". This appears to be a typo; perhaps "Cascading Outages" was intended or was "cascading" not meant to be capitalized?FAC-011-2 R2.2 uses the capitalized word "Cascading". This appears to be a typo; perhaps "Cascading Outages" was intended or was "cascading" not meant to be capitalized?
SERC OC Standards Review Group	None of the requirements in FAC-10, 011 or 014 have VRS or time horizons identified. In FAC-011, R 2.3.2, the following language that was previously removed has been reinserted - "e.g., load greater than studied" - and should be removed. In FAC-010, Requirement 2.2, the word "outages" should be deleted - it is not a part of the definition for "Cascading."
OPPD	In FAC-010, the word "outages" still needs to be removed from R2.2, and the letter "o" needs to be removed from E1.2.2 and E1.3.1.
SPP Operating Reliability Working Group	In FAC-010, R2.2 and R2.5 and FAC-011, R2.2 cascading outages should not be capitalized indicating it is a defined term. In FAC-010, R2.3 a reference is made to Footnote 2 but the footnote is missing.In FAC-011, R2.3 remove the Footnote 2 since the footnote itself has been deleted.
FirstEnergy	1. Since the ATFN SDT is in the process of consolidating TPL-001 through TPL-004, it may help to

	revise FAC-010 R2.5 & R2.6 and FAC-011 R6 to be more general and remove specific reference to TPL-003. We suggest replacing the phrase "Reliability Standard TPL-003" with "the TPL series of reliability standards".
HydroOne Networks, Inc.	We noticed some change control/editorial errors that may have been overlooked. They include: FAC-010-2: R2.2 remove the word "outage" completely. FAC-010-2: R2.3 remove the reference to the second footnote after the word "following" FAC-011-2: R2.3 remove the reference to the second footnote after the word "acceptable" FAC-011-2: R2.3.2 remove "e.g., load greater than studied" as stated in the Consideration for Comments for Version 1 of the SAR As well, Violatin Risk Factors and Time Horizons need to be established and reviewed for these standards.
ATC	Comments on the SAR: Issue 1: The SAR states that the phrase "i.e. load greater than studied" in FAC-011-1 R2.3.2 will be deleted but this was not shown in either the red-line or clean version of the standard. Is is still the intention of the SDT to removed this phase? Issue 2: NERC's BOT has already overturn their earlier approval for the term "Cascading Outage". The following Statement appears in NERC's Glossary of Terms: "On December 27, 2007, the FERC remanded the definition of "Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustee withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FAC standards drafting team and the revised standards that are developed through the standards development process. Therefore, the definition is no longer in effect.

	With the NERC BOT withdraw of their prior approval and the FERC remand ATC does not believe that the SAR needs to address this definition. The only thing that the SAR must address is the term "Cascading Outage" is used in FAC-010, FAC-011 and FAC-014. Why does the SDT believe that they have to address a definition issue when both NERC BOT and FERC have not approve the definition? Question on what will be replacing the term "Cascading Outage": In FAC-010-1 Requirement 2.2 (redline version) the SDT is proposing to replace term "Cascading Outage" with the phrase "Cascading outage" but in requirement 2.5 the SDT is replacing it with only the term "Cascading". Is it the intention of the SDT to replace the term "Cascading Outages" with the phrase "Cascading outages" or only with the term "Cascading"? It's ATC's preference that the term "Cascading Outages" be replaced with the term "Cascading".

Consideration of Comments on Second Posting of SAR and FAC-010-2, FAC-011-2, FAC-014-2 for Order 705

The drafting team working on the modifications to FAC-010-1, FAC-011-1, and FAC-014-1 to comply with Order 705 thanks all commenters who submitted comments on the revised SAR and associated proposed modifications to the following standards:

FAC-010 — System Operating Limits Methodology for the Planning Horizon

FAC-011 — System Operating Limits Methodology for the Operations Horizon

FAC-014 — Establish and Communicate System Operating Limits.

This SAR and associated standards were posted for a 30-day public comment period from March 31 through April 29, 2008. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were 13 sets of comments, including comments from more than 60 different people from more than 45 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The drafting team made only clarifying edits to the documents, based on stakeholder comments. Based on the comments received, the drafting team is recommending that the Standards Authorization Committee authorize moving the standards forward to ballot.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Facility_Ratings_Project_2008-04.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

		Industry Segments									
Commenter	**Company**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Anita Lee	AESO		x								
John Sullivan (G3)	Ameren	x									
Jason Shaver	ATC	x									
Chris Bradley (G2)	Big Rivers Electric Cooperative	x		x							
Brent Kinsford	CAISO		x								
Danny McDaniel (G4)	CLECO	x		x		x					
Ed Thompson (G1)	Consolidated Edison Co. of New York	x									
Michael Gildea (G1)	Constellation Energy						x				
Ron Hart (G1)	Dominion Resources, Inc.					x					
Jack Kerr (G2)	Dominion Virginia Power			x		x	x				
Louis Slade (G2)	Dominion Virginia Power										
Greg Rowland (G2)	Duke Energy - Carolinas	x		x							
Brian Berkstresser (G4)	Empire District Electric	x		x		x					
Ed Davis	Entergy	x									
Steve Myers	ERCOT										x
Dave Folk	FirstEnergy	x		x		x	x				
Doug Hohlbaugh	FirstEnergy	x		x		x	x				
Sam Ciccone	FirstEnergy	x		x		x	x				
Wayne Pourciau (G2)	Georgia System Operations Corp.	x		x							
Ross Kovacs (G2)	Georgia Transmission Corp.	x									
David Kiguel (G1) (I)	Hydro One Networks, Inc.	x									
Roger Champagne (G1)	Hydro-Quebec TransEnergie		x								
Sylvain Clermont (G1)	Hydro-Quebec Trans-Energie	x									

Commenter	Company	Industry Segments 1	2	3	4	5	6	7	8	9	10
Ron Falsetti (G5) (G1)	Independent Electricity System Operator		x								
Kathleen Goodman (G1)	ISO - New England		x								
Matt Goldbery	ISO-NE		x								
Mike Gammon (G4)	Kansas City Power and Light	x		x		x					
Dan Jewell (G2)	Louisiana Generating, LLC	x		x	x						
Don Nelson (G1)	Massachusetts Dept. of Public Utilities									x	
Scott Goodwin (G2) (G3)	Midwest ISO		x								
Bill Phillips	MISO		x								
Nabil Hitti (G1)	National Grid				x						
Michael Schiavone (G1)	National Grid US	x									
Randy MacDonald (G1)	New Brunswick System Operator		x								
William DeVries (G1)	New York Independent System Operator		x								
Ralph Rufrano (G1)	New York Power Authority	x									
Guy Zito (G1)	NPCC										x
Lee Pedowicz (G1)	NPCC										x
Jim Castle	NYISO		x								
Don Hargrove (G4)	Oklahoma Gas & Electric	x		x		x					
John Mayhan	OPPD	x									
Patrick Brown	PJM		x								
Mike Bryson (G2)	PJM Interconnection		x								
Rick White	Northeast Utilities	x									
Sara McCoy	Salt River Project	x		x		x	x				
Phil Kleckley (G3)	SC Electric and Gas			x							
Carter Edge (G2)	SERC										x

Commenter	Company	Industry Segments 1	2	3	4	5	6	7	8	9	10
John Troha (G2)	SERC										x
Pat Huntley (G3)	SERC										x
Jim Griffith (G2)	Southern Company	x		x							
Marc Butts (G2)	Southern Company	x		x							
Bob Jones (G3)	Southern Company Services	x									
Jason Smith (G4)	Southwest Power Pool										x
Robert Rhodes (G4)	Southwest Power Pool										x
Charles Yeung	Southwest Power Pool										x
Kyle McMenamin (G4)	Southwestern Public Service	x		x		x					
Donald Drum (G2)	Tennessee Valley Authority	x		x						x	
Joel Wise (G2)	Tennessee Valley Authority	x		x						x	
Travis Sykes (G3)	Tennessee Valley Authority	x									
Walter Joly (G2)	Tennessee Valley Authority	x		x						x	
Allen Klassen (G4)	Westar Energy	x		x		x					

Legend:
G1 – NPCC Regional Standards Committee, RSC
G2 – SERC OC Standards Review Group
G3 - SERC EC Planning Standards Subcommittee
G4 - SPP Operating Reliability Working Group
G5 - IRC Standards Review Committee

I – indicates this person submitted individual comments in addition to the identified group comments

Question 1 – Several stakeholders indicated that the Assess Transmission Future Needs SDT working on revisions to the "TPL" series of standards has proposed a NERC definition of "Consequential Load Loss." Because Order 705 did not direct NERC to include this footnote in FAC-010 and FAC-011, and because NERC has already made a commitment to modify the ATC-related standards to align with the TPL standards when they are revised, the drafting team has elected to remove the footnote from the revised standards. Do you agree with this change?

Summary Consideration:
Most commenters supported this change.

Entergy	No	We suggest the TPL series of standards and these FC standards should be properly aligned at the appropriate time.
Response: The proposal is to allow the drafting team working on the TPL standards to refine the definition, with stakeholders, and then to make conforming changes (through the TPL implementation plan) to the FAC standards.		
NPCC RSC	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
Response: Thank you for your support of the drafting team's suggestion. In the first draft of the proposed revisions to FAC-011-2, the drafting team had proposed adding the term in a footnote associated with R2.3.		
Northeast Utilities	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
Response: Thank you for your support of the drafting team's suggestion. In the first draft of the proposed revisions to FAC-011-2, the drafting team had proposed adding the term in a footnote associated with R2.3.		
IESO	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
Response: Thank you for your support of the drafting team's suggestion. In the first draft of the proposed revisions to FAC-011-2, the drafting team had proposed adding the term in a footnote associated with R2.3.		
IRS SRC	Yes	This term is not in the Board of Trustee's approved versions so we are not clear on the basis of this change. In any event, we concur that references to this term, if any, should be removed pending outcome of the TPL standard development.
Response: Thank you for your support of the drafting team's suggestion. In the first draft of the proposed revisions to FAC-		

011-2, the drafting team had proposed adding the term in a footnote associated with R2.3.		
SERC EC PSS	Yes	Please remove the reference to footnote in R2.3 in FAC-010 and 011.
Response: The erroneous references to the deleted footnote have been removed as proposed from both FAC-010 and FAC-011.		
FirstEnergy	Yes	The standards as proposed still show the superscript no. 2 for this removed footnote in R2.3.
Response: The erroneous references to the deleted footnote have been removed as proposed from both FAC-010 and FAC-011.		
OPPD	Yes	However, in both FAC-010 and FAC-011, the superscript "2" at the end of R2.3 needs to be removed.
Response: The erroneous references to the deleted footnote have been removed as proposed from both FAC-010 and FAC-011.		
ATC	Yes	ATC agrees with this decision.
Response: Thank you for your support of the drafting team's suggestion.		
Hydro One Networks, Inc.	Yes	
SERC OC SRG	Yes	
SPP ORWG	Yes	

Question 2 - Do you agree with the Violation Severity Levels proposed for FAC-010?

Summary Consideration:
Most commenters disagreed with the proposed VSLs for R1 and R2, based on an assumption that all of the subrequirements within each requirement in FAC-010-2 are of equal weight. VSLs identify categories of noncompliant performance associated with each requirement. Note that VSLs come into use after a violation has already occurred – the VSLs need to be set up so that the degree of violation identified fits with one of the VSLs.

When the drafting team proposed VSLs, they used the following thought process:

The intent of each requirement should be addressed in total – because the individual subrequirements, by themselves, don't reflect the deliverable product or process that is the intent of the requirement. Each subrequirement contributes to the overall requirement, but has little value by itself. For some requirements, there are several subrequirements, and each subrequirement is of equal, or near equal weight in contributing to the achievement of the overall requirement. These requirements can have VSLs assigned using the "Multi-component" methods in the VSL Guidelines. Where the subrequirements are not of equal weight, the use of the Multi-component method of assigning VSLs does not support the intent of appropriately dividing the categories of noncompliant performance.

Stakeholders proposed using the multi-component method of assigning VSLs for Requirement R1, and R2 and the drafting team provides the following reasoning for leaving the VSLs as they are:

Requirement 1 - There are three subrequirements for R1 – to be applicable for use in the planning horizon (R1.1) to state that SOLs shall not exceed Facility Ratings (R1.2) and to include a description of how to identify IROLs (R1.3).

The drafting team felt that of these three subrequirements, if R1.2 were missing, it would still be possible to have a technically sound methodology – in other words, the methodology may meet the intent of this subrequirement without specifically including the statement in the methodology.

The drafting team also felt that the methodology may be useful, albeit incomplete, if it did not include a method of identifying the subset of SOLs that are IROLs – thus the classification of a "High" VSL.

However, if the methodology is not suitable for use in the planning horizon, it has no use to the Planning Authority and has totally failed to meet the intent of the requirement – thus the classification of a "Severe" VSL.

Requirement 2 – There are six subrequirements for R2 – R2.1 identifies performance in the pre-contingency state – R2.2 and R2.3 and R2. 4 address single contingencies – and R 2.5 and R2.6 address multiple contingencies. From a planning perspective, if the methodology is missing one of these three topical areas, then missing the pre-contingency state is the least severe, and missing the single contingencies is the most severe because the single contingencies are the most prevalent.

If the methodology does not address system performance in the pre-contingency state, but does address system performance following one or more contingencies, then this is not as severe as having a methodology that doesn't address single contingencies or multiple contingencies. Similarly, if the methodology does address single contingencies but is missing multiple contingencies, this is not rated as severe as missing the single contingencies. The SOLs based on contingencies are generally more conservative than those based on precontingency conditions.

NPCC Regional Standards Committee, RSC	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe. R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs. R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Response: The drafting team did not modify the VSLs as proposed because the subrequirements are not all of equal weight. Please see the summary consideration above.		
SERC OC Standards Review Group	No	The "Severe" Violation Severity Level for R3 overlaps the "High" Violation Severity Level. The word "three" should be replaced with "four" to prevent this overlap, i.e., The Planning Authority has a methodology for determining SOLs that is missing a description of "four" or more of the following: R3.1 through R3.6Under the "Moderate" Violation Severity Level for R4 (first line), the word "or" should be changed to "of".
Response: Agreed – the proposed correction was made to eliminate this overlap.		
SERC EC Planning Standards Subcommittee	Yes	The VSL for R4 should read "One of the following."
Response: Agreed – the proposed correction was made.		

SPP Operating Reliability Working Group	No	We find it difficult to determine which of the subrequirements is more critical than the other in R1. Therefore we suggest the SDT change the VSLs to something like the following: The Planning Authority has a documented SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Finally, substitute three subrequirements for one and assign a Higher category.We would suggest removing the first paragraph (above the 'or') in the Severe category. For R2, we suggest rewording the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another.The Severe VSL for R3 should be changed to read '?four or more of the following:' The VSLs for R4 add an additional requirement to R4 by stipulating a specific time reference for the requirement. We would suggest eliminating the timing aspects and revise the VSLs to parallel what we proposed for the VSLs for R1. For R5, delete the phrase '?but less than 60 calendar days.' from the Lower VSL. We would suggest the following language for the Moderate category: 'The Planning Authority in their response did not include statements regarding changes or no changes to their SOL methodology.' Delete the first paragraph (above the 'or') of the VSL in the Higher category and keep the second paragraph (below the 'or'). Change the Severe category to the following: 'The Planning Authority failed to respond.'
R1 – Please see the summary consideration. R2 – Please see the summary consideration. R4 – The requirement states that the distribution must take place, "prior to the effectiveness of the change". This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place before the change, but did take place, there is a category of VSL to capture the noncompliant performance. R5 – The drafting team considered using the phrase, "The Planning Authority failed to respond" but envisioned the situation where the auditor requests evidence of a response, and the entity claims that the response is under development but hasn't been completed and delivered – the outer boundary of 90 calendar days was intended to clarify that if the response hasn't been provided within 90 days, then it can be considered to have not been provided.		
Northeast Utilities	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe.

		R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Response: The drafting team did not modify the VSLs as proposed because the subrequirements are not all of equal weight. Please see the summary consideration above.		
Ontario IESO	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL guideline, progressive VSLs should simply be dependent on how many or the percentage of those sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe.R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive violation level. Suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: Agreed. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Response: The drafting team did not modify the VSLs as proposed because the subrequirements are not all of equal weight. Please see the summary consideration above.		
IRC Standards Review Committee	No	R1: The progressive levels should not be dependent on which one of the 3 sub-requirements is violated since by doing so, the "impact" factor is included. In accordance with the VSL criteria guideline document, progressive (graded) VSLs should be made dependent on how many or the percentage of the sub-requirements not met. For example, if the SOL Methodology missed one of the three, then the VSL is a Medium, 2/3 a High, and 3/3 a Severe, etc.R2: Similar comments as in R1 but this one is a bit more complicated. We are unable to provide a simple example on the determination of the progressive (graded) VSLs. We suggest the SDT to review and revise these levels, giving consideration to changing the sub-requirements that can better facilitate the development of VSLs.R3 to R5: We agree with these VSLs. The approach taken for these requirements should be the basis for developing the VSLs for R1 and R2.
Response: The drafting team did not modify the VSLs as proposed because the subrequirements are not all of equal weight. The focus is on the contribution of each of the subrequirements in achieving the objective of the requirement. If the methodology is not suitable for use in the planning horizon, then the methodology totally misses the objective of the		

requirement – whereas if the methodology includes everything but a statement relative to respecting Facility Ratings, then the methodology is incomplete, but the requirement has been partially met. Please see the summary consideration above.		
Entergy	No	We suggest the removal of the term "outage" from FAC-010-2 R2.2.
Response: Agreed – the proposed correction was made.		
Hydro One Networks, Inc.	No	The VSLs for requirement R1 should weigh all violations of the 3 sub-requirements equally. For example, missing one of the three sub-requirements in the SOL methodology should result in a Medium VSL, missing two of three should result in a High VSL and missing all three should result in a Severe VSL and maintain having no SOL methodology as Severe. We agree with VSLs for requirements R2 and R3 however we find the VSL for R4 overly complex. We suggest HIGH: One of the following: (1)The Planning Authority failed to issue its SOL methodology and changes to that methodology to one of the required entities or (2) For a change in methodology, the changed methodology was issued after the effictiveness of the change but up to 30 calendar days after the effectiveness. SEVERE: One of the following: (1)The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than one of the required entities or (2) For a change in methodology, the changed methodology was issued 30 calendar days or more after the date of effectiveness of the change.
Response: R1 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R4 - The proposed modifications would limit the variations in noncompliant performance that were identified in the set of VSLs. The drafting team had attempted to identify a full range of possible categories of noncompliant performance that uses as many of the four VSLs as practical.		
ATC	No	The ranking of the R1 levels should be lowered and the typographical error in R3 should be corrected. R1: Move omission of R1.2 (facility rating statement) from Moderate to Lower. Move omission of R1.3 (IROL description) from High to Moderate. Move omission of R1.1 (applicable to planning horizon SOLs) from Severe to High. Add omission of all three requirements to the Severe Level.

		R3: Correct typographical error in Severe Level text from “three or more” to “four or more”
Response: R1 – No justification has been provided for lowering the VSLs. Please see the summary consideration for the drafting team’s reasoning in assigning the VSLs. If the methodology is not suitable for use in the planning horizon, it has no value and the intent of the requirement has been totally missed – meeting the criteria for a “Severe” VSL. R3 - Agreed – the proposed correction to R3 was made.		
FirstEnergy	Yes	

Do you agree with the Violation Severity Levels proposed for FAC-011?

Summary Consideration:
Most commenters indicated disagreement with the proposed VSLs – some pointed out typographical errors which have been corrected – others disagreed with the method of assigning VSLs and proposed using the Multi-component method of assigning VSLs. The drafting team did not adopt the Multi-component method of assigning VSLs, because the Multi-component method is only applicable when all subrequirements were of equal weight in contributing to the achievement of the requirement. Note that VSLs come into use after a violation has already occurred – the VSLs need to be set up so that the degree of violation identified fits with one of the VSLs.

When the drafting team proposed VSLs, they used the following thought process:

The intent of each requirement should be addressed in total – because the individual subrequirements, by themselves, don't reflect the deliverable product or process that is the intent of the requirement. Each subrequirement contributes to the overall requirement, but has little value by itself. For some requirements, there are several subrequirements, and each subrequirement is of equal, or near equal weight in contributing to the achievement of the overall requirement. These requirements can have VSLs assigned using the "Multi-component" methods in the VSL Guidelines. Where the subrequirements are not of equal weight, the use of the Multi-component method of assigning VSLs does not support the intent of appropriately dividing the categories of noncompliant performance.

Stakeholders proposed using the multi-component method of assigning VSLs for Requirement R1, and R2 and the drafting team provides the following reasoning for leaving the VSLs as they are:

Requirement 1 - There are three subrequirements for R1 – to be applicable for use in the operations horizon (R1.1) to state that SOLs shall not exceed Facility Ratings (R1.2) and to include a description of how to identify IROLs (R1.3).

The drafting team felt that of these three subrequirements, if R1.2 were missing, it would still be possible to have a technically sound methodology – in other words, the methodology may meet the intent of this subrequirement without specifically including the statement in the methodology.

The drafting team also felt that the methodology may be useful, albeit incomplete, if it did not include a method of identifying the subset of SOLs that are IROLs – thus the classification of a "High" VSL.

However, if the methodology is not suitable for use in the operations horizon, it has no use to the Reliability Coordinator and has totally failed to meet the intent of the requirement – thus the classification of a "Severe" VSL.

Requirement 2 – There are four subrequirements for R2 – R2.1 identifies performance in the pre-contingency state – R2.2 and R2.3 and R2. 4 address single contingencies. From an operations perspective, if the methodology is missing one of these two topical areas, then missing the pre-contingency state is the least severe, and missing the single contingencies is the most severe because the single contingencies are the most prevalent.

NPCC Regional Standards Committee, RSC	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them. Mathematical methods can be applied to sub-requirements only if each sub-requirement is deemed to be of equal importance. If not, and the sub-requirements have different levels of importance, then some consideration should be given to the order in which they are employed in the mathematical formula.
R1 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R2 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement.		
Northeast Utilities	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them. Mathematical methods can be applied to sub-requirements only if each sub-requirement is deemed to be of equal importance. If not, and the sub-requirements have different levels of importance, then some consideration should be given to the order in which they are employed in the mathematical formula.
R1 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R2 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement.		
Ontario IESO	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them.
R1 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R2 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the		

achievement of the requirement.		
IRC Standards Review Committee	No	The structure of FAC-011 closely resembles that of FAC-010, hence, the same comments as in Q2 on R1 and R2, above apply (i.e. progressive (graded) versus impact factor). However, R3 is slightly different as it has 7 sub-requirements rather than 6 as in the case of FAC-010. Failing 1/7 is <25%, 2-3/7 < 50%, 4-5 <75% and 6-7 >75%. This would make a slight difference in the Medium, High and Severe levels. Please consider revising them.
R1 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R2 – Please see the summary consideration above. The subrequirements are not of equal weight in contributing to the achievement of the requirement. R3 – The format of the VSLs in the proposed standard is less complex than the proposed use of percentages. Percentages are most applicable when there are large quantities being measured – in this case, there are only 7 elements required – and the use of whole numbers rather than fractions is simpler.		
SERC OC Standards Review Group	No	The headings for the Violation Severity Levels are missing from the table. Under the "Severe" Violation Severity Level for R2, the word "either" should be deleted from the sentence. Under the "Severe" Violation Severity Level for R4, the reference to "Planning Authority" should be replaced with "Reliability Coordinator".
Response: The headings have been added to the VSL table as noted. The word, “either” was removed from the Severe VSL for R2 as noted. The title, “Planning Authority” was replaced with “Reliability Coordinator” as noted in the Severe VSL for R4.		
SPP Operating Reliability Working Group	No	We again find it difficult to determine which of the subrequirements is more critical than the other in R1. Therefore we suggest the SDT change the VSLs to something like the following: The Reliability Coordinator has a documented SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Finally, substitute three subrequirements for one and assign a Higher category.We would suggest removing the first paragraph (above the 'or') in the Severe category. For R2, we suggest rewording the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another.The Severe VSL should for R3 should be changed to read '?four or more of the following:' The VSLs for R4 add an additional requirement to R4 by stipulating a specific time reference for the requirement. We would suggest eliminating the timing aspects and revise the VSLs to parallel what we proposed for the VSLs for R1. Change the VSLs for R5 to match those we proposed in R5 of FAC-010 except replace Planning Authority with Reliability Coordinator
Response: Please see the summary consideration above for the drafting team’s reasoning in giving different “weight” to certain R1 and R2 subrequirements.		

The typographical error in the Severe VSL for R3 was corrected and "three" was changed to "four" as noted. R4 – The requirement states that the distribution must take place, "prior to the effectiveness of the change". This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place before the change, but did take place, there is a category of VSL to capture the noncompliant performance. R5 – The drafting team considered using the phrase, "The Reliability Coordinator failed to respond" but envisioned the situation where the auditor requests evidence of a response, and the entity claims that the response is under development but hasn't been completed and delivered – the outer boundary of 90 calendar days was intended to clarify that if the response hasn't been provided within 90 days, then it can be considered to have not been provided.		
Entergy	No	Order 705 contains comments about removing the term "load greater than studied", or address FERC's concerns with the use of the term. It seems the term is still in the standard and we think FERC's concerns have not been addressed. Please remove the term or address FERC's concerns.
Response: Agreed – the drafting team removed the example from R2.3.2 as proposed.		
Hydro One Networks, Inc.	No	We agree with VSLs for requirements R1, R3 and R5 however we find the VSL for R4 overly complex. We suggest HIGH: One of the following: (1)The Reliability Coordinator failed to issue its SOL methodology and changes to that methodology to one of the required entities or (2) The Reliability Coordinator failed to issue its SOL methodology and changes to that methodology prior to the date of effectiveness but up to 2 days after the date of effectiveness. Here we suggest using 2 days as opposed to 30 days in FAC-010 because this is in the Operating Horizon and not the Planning Horizon. SEVERE: One of the following: (1)The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than one of the required entities or (2) The Reliability Coordinator issued its SOL methodology and changes to that methodology 3 days or more after the date of effectiveness. As well, in the Severe VSL for R2, it is not clear the use of the word "either". We suggest deleting this word.
Response: R4 – The drafting team did not adopt the proposed revision. The proposed modifications would limit the variations in noncompliant performance that were identified in the set of VSLs. The drafting team had attempted to identify a full range of possible categories of noncompliant performance that uses as many of the four VSLs as practical. The drafting team considered the suggestion that we change the threshold for lower VSL from 30 days to 2 days – there should not be a considerable difference in operations when comparing the 2 days with the 30 days. The word, "either" was removed from the Severe VSL for R2 as noted.		
ATC	No	VSL's for R4 FAC-011 requirement 4 specifies that the RC issue its SOL Methodology and changes to their

		methodology. Suggested Modification: Have only one VSL in the Moderate level that states the following: The RC did not issue its SOL Methodology or changes to its methodology to all required entities. We find our approach makes the VSLs for this requirement simpler to understand and determine. VSL's for R5 Requirement 5 specifies that the RC has to provide documented technical comments within 45 calendar days following receipt of comments. Suggested Modification: Have only one VSL in the lower level that states the following: The RC did not provide technical comments within 45 calendar days following receipt of comments.
Response: The proposed modifications would limit the variations in noncompliant performance that were identified in the set of VSLs and the proposed modifications don't support the default criteria for assigning VSLs. An entity that fully misses complying with a requirement has a "Severe" violation severity level. The drafting team had attempted to identify a full range of possible categories of noncompliant performance that uses as many of the four VSLs as practical. An entity that does not provide a response to technical comments within 45 days of receipt is fully noncompliant according to the criteria for assigning categories of VSLs.		
FirstEnergy	Yes	

Do you agree with the Violation Severity Levels proposed for FAC-014?

Summary Consideration:
Most commenters indicated disagreement with the proposed VSLs. Several stakeholders disagreed with the method of assigning VSLs and proposed using the Multi-component method of assigning VSLs. The drafting team did not adopt the Multi-component method of assigning VSLs, because the Multi-component method is only applicable when all subrequirements were of equal weight in contributing to the achievement of the requirement. Note that VSLs come into use after a violation has already occurred – the VSLs need to be set up so that the degree of violation identified fits with one of the VSLs.

When the drafting team proposed VSLs, they used the following thought process:

The intent of each requirement should be addressed in total – because the individual subrequirements, by themselves, don't reflect the deliverable product or process that is the intent of the requirement. Each subrequirement contributes to the overall requirement, but has little value by itself. For some requirements, there are several subrequirements, and each subrequirement is of equal, or near equal weight in contributing to the achievement of the overall requirement. These requirements can have VSLs assigned using the "Multi-component" methods in the VSL Guidelines. Where the subrequirements are not of equal weight, the use of the Multi-component method of assigning VSLs does not support the intent of appropriately dividing the categories of noncompliant performance.

Stakeholders proposed using the multi-component method of assigning VSLs for Requirement R1, and R2 and the drafting team provides the following reasoning for leaving the VSLs as they are:

Requirement R5: The subrequirements for R5.1 do not all provide an equal contribution in meeting the intent of the requirement. The intent of the subrequirement is to provide IROL values and associated information to the entities that need those IROL values. There are four sub-subrequirements – to provide the IROL value, to provide the IROL T_v, to provide the contingency associated with the IROL, and to identify the type of limitation (such as voltage collapse) represented with the IROL. The VSLs are set so that the failure to provide the limit or its T_v is a "Severe" violation – the failure to provide the contingency associated with the limit is a "High" VSL and the failure to identify the type of limitation is a "Moderate" VSL. If no IROL values are provided, or if the IROL values are provided without their associated T_v, the IROL values can't be used and the intent of the requirement has not been met. If the IROLs and IROL T_vs are provided, but the associated contingencies are not provided, then the limits can still be used, but they aren't as useful as they would be if the associated contingencies were identified – thus the intent of the requirement has been partially met. Similarly, if the IROLs, the IROL T_vs and the contingencies were all provided, but the type of limit wasn't identified, the IROLs could still be used – knowing the type of limit provides a more complete picture of the possible impact of exceeding the IROL, but failure to provide the type of limit is not nearly as bad as not providing the IROL values and not nearly as bad as failure to provide the associated contingencies.

Requirement R6: Several commenters suggested revising the VSLs for R6, and proposed that the intent of the requirement was to have the Planning Coordinator identify stability-related multiple contingencies. The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all.

NPCC Regional Standards Committee, RSC	No	(1) We applaud the SDT for developing progressive VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any criteria or guidleine on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor folks conduct a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report on compliance. Alternatively (not preferred), the requirement is viewed as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go through the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would consitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
Response: The drafting team will research the process of developing compliance guidelines.		

R5 - The subrequirements for R5.1 do not all provide an equal contribution in meeting the intent of the requirement. Please see the summary consideration above. R6 – The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all.		
SERC OC Standards Review Group	No	The language for identifying the ranges of inconsistency with the RC methodologies under each severity level for each of Requirements R1 - R4 is very confusing and misleading. There is no need to state that "there are SOLs"?. because this standard would not apply if there were none. We would suggest the following language for R1 VSLs and similar language for R2 - R4 VSLs: "Lower": Up to 25% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "Moderate" 26 to 50% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "High": 51 to 75% of the SOLs identified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1) "Severe": More than 75% of the SOLsidentified for the Reliability Coordinator Area are inconsistent with the Reliability Coordinator?s SOL Methodology. (R1)For R3 and R4 under all VSLs, the "Planning Cooordinator" should be changed to the "Planning Authority". Under R4 for the "High" VSL, "Reliability Coordinator" should be changed to "Planning Authority".
Response: The intent of each VSL is to identify a category of nonperformance that may occur. The compliance enforcement authority will review performance, and if the performance does match the required performance, then the compliance enforcement authority looks at the VSLs to see which VSL best describes the performance that was measured. The qualifying language surrounding the percentages used for each of the VSLs was adopted based on the "lessons learned" from the VSL drafting team. The exact language eliminates ambiguity. The typographical error in R4 was corrected, and "Reliability Coordinator" was changed to "Planning Authority."		
SPP Operating Reliability Working Group	No	The VSLs for R5 introduce a specific timing requirement that is not included in R5. This should be deleted. We find it difficult to determine which of the subrequirements is more critical than the other in R5. Therefore we suggest the SDT change the VSLs to something like the following: The responsible entity has communicated its SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Substitute three subrequirements for one and assign a Higher category. Finally, substiture four subrequirements for one and assign a Severe category.In R6 we suggest moving the Higher category VSL to the empty Moderate category. Move the second paragraph of the Severe category to the Higher category. Leave the first paragraph of the Severe

		category as the only entry for the Severe category.
Response: R5 - The requirement states that the entity requesting the limits must deliver limits to those entities that request them and provide a "a schedule for delivery of those limits." The measure requires evidence that the limits were delivered as requested. This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place "as scheduled," but did take place, there is a category of VSL to capture the noncompliant performance.		
Northeast Utilities	No	(1) We applaud the SDT for developing progressive VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any criteria or guidleine on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor folks conduct a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report on compliance. Alternatively (not preferred), the requirement is viewed as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go through the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would consitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which (i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
Response: The drafting team will research the process of developing compliance guidelines.		

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(2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met.

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Response: The drafting team will research the process of developing compliance guidelines. R5 - The subrequirements for R5.1 do not all provide an equal contribution in meeting the intent of the requirement. Please see the summary consideration above. R6 – The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all.		
IRC Standards Review Committee	No	(1) We commend the SDT for developing progressive (graded) VSLs for R1 to R4. However, it may be very difficult for a responsible entity to report via the self-certification process absent any guideline on what 1-25%, 26-50% etc. of "inconsistency" with SOL methodology really means. This can become a dispute when the Compliance Monitor conducts a site audit as well. A suggestion is to establish a compliance guideline for use by the Compliance Auditor and make this guideline a/v to those required to self report compliance. Alternatively (not preferred), the requirement can be treated as a binary type, i.e. either it is 100% consistent with the SOL methodology or be assigned a Severe VSL otherwise. (2) For R5, we agree with the VSLs that are based on the number of entities not provided the SOLs and the number of days missing the scheduled delivery, but we do not agree with tying the VSLs to which of the sub-requirements are not met (similar comments on R1 and R2 of FAC-010). Suggest the SDT to revisit this. A possible way to change this is to make VSLs progressive depending on the number of sub-requirements in R5.1 that are not met. (3) For R6, we see a main requirement and two mutually exclusive sub-requirements. The main requirement is the PC "identify" the subset of multiple contingencies associated with stability limits. After doing that, the PC shall provide this list to the RC. Where the PC does not have any of these identified (note that the wording in R6.2 could be misinterpreted as the PC does not go throught the identification process at all), then it shall inform the RC that there is none identified.We would expect that not going through the identification process would consitute a complete violation of this requirement. Having gone through the identification exercise, failing to provide RC the list or failing to inform the RC that there are no such contingencies identified would constitute a lessor degree of violation since the PC has already met the requirement to go through the identification exercise. With this rationale, we'd expect a Low, Medium or High or even Severe for not meeting either R6.1 or 6.2, depending on the number of affected parties not provided the list or notified of none found, as opposed to determining the VSL based on which of R6.1 and R6.2 not met. In other words, R6.1 and R6.2 should be treated equally, and the level of violation would depend on the extent to which

		(i.e. the number of) RCs are not provided the list or informed. The Severe level assigned to not identifying the subset is proper, but it needs to have another component that's caused by a high number of RCs that did not receive a list (R6.1) or notification (R6.2).
Response: The drafting team will research the process of developing compliance guidelines. R5 - The subrequirements for R5.1 do not all provide an equal contribution in meeting the intent of the requirement. Please see the summary consideration above. R6 – The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all.		
Entergy	No	The Version History contains a note that "Cascading Outage" was changed to "Cascading". We suggest that note be removed since the change does not apply to this standard.
Response: Agreed. The notation in the Version History was modified to remove the reference to changing “Cascading Outage” to “Cascading” as proposed.		
FirstEnergy	No	The following are potential issues with the VSL for FAC-014-1: 1. R5 - The VSL do not address situations when the entities do not provide the subset of SOLs that are also considerd potential IROLs. We suggest replacing the phrase "The responsible entity provided its SOLs" with "The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) throughout the R5 VSLs where appropriate. 2. General - The main requirement number (ex. R5) does not need to be shown in parenthesis after the text of the VSL since the VSL table is arranged based on the main requirements. This is only useful if the VSL is geared toward a specific subrequirement (ex. R5.1).
Response: The drafting team adopted the suggestion to add the clarifying text, “including the subset of SOLs that are IROLs” to all the VSLs in R5 as proposed. While the main requirement number is not needed when the VSLs are displayed in the table, the standards will eventually be entered into a database where this information may be helpful.		
HydroOne Networks	No	For the VSLs for requirements R1, R2, R3 and R4 we suggest only High and Severe VSLs. Example, High: "There are SOLs for the Reliability Coordinator Area, but from 1% to 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology." Severe: "There are SOLs for the Reliability Coordinator Area, but more than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology." We suggest VSLs for R1, R2, R3 and R4 all follow the same pattern as the example provided.

		We find the VSLs for R5 to be well thought out but overly complex due to format of the requirement itself. We suggest breaking up the requirement into several requirements by isolating the responsible entity and their responsibilities. As well, for R6 we suggest a Severe VLS for violoation of the "parent" requriement R6 and a High VSLs for violation of either sub-requirement R6.1 and R6.2. Example: HIGH: One of the following: The Planning Authority identified a list of multiple continegnecies and associated stability limits, via studies, however the PA failed to provide thse to the RC that monitors the facilities asscoiated with those contingencies and limits. or (2) The Planning Authority, via studies, did not identify any stabilityrelated multiple contingencies, however the PA failed to notify the RC of this outcome. SEVERE: The Planning Authority did not conduct studies to indenify if a subset of multiple contingencies from the Standard TPL-003 result in stability limits.
Response: The drafting team did not adopt the proposed revision to R1, R2, R3, and R4. The proposed modifications would limit the variations in noncompliant performance that were identified in the set of VSLs. The drafting team had attempted to identify a full range of possible categories of noncompliant performance that uses as many of the four VSLs as practical. R5 – Although the VSLs are complex, they address the range of noncompliant performance associated with Requirement R5. R6 - The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all. Please see the summary consideration.		
ATC	No	VSL's for R5 Requirement 5 specifies that the RC, PA and TP provide its SOLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits. Suggested Modification: Have only one VSL in the Moderate level that states the following: The RC, PA or TP did not provide its SOLs to those entities that have a reliability-related need for those limits per the schedule.

Response: The proposed modifications would limit the variations in noncompliant performance that were identified in the set of VSLs and the proposed modifications don't support the default criteria for assigning VSLs. An entity that fully misses complying with a requirement has a "Severe" violation severity level. The drafting team had attempted to identify a full range of possible categories of noncompliant performance that uses as many of the four VSLs as practical.

An entity that does not provide its SOLs to the entities that need them is fully noncompliant – which is classified as a "Severe" VSL.

SERC EC Planning Standards Subcommittee	Yes	

If you have any other comments on the revised SAR or standards that you haven't already made in response to the first four questions, please provide them here.

NPCC Regional Standards Committee, RSC	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it.
Response: The word, "outages" was removed from R2.2 and the two extra "o's" in the WECC Regional Variance have been removed. The reference to the footnote was a typographical error and has been removed.	
Northeast Utilities	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it.
Response: The word, "outages" was removed from R2.2 and the two extra "o's" in the WECC Regional Variance have been removed. The reference to the footnote was a typographical error and has been removed.	
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Response: The word, "outages" was removed from R2.2 and the two extra "o's" in the WECC Regional Variance have been removed. The reference to the footnote was a typographical error and has been removed.	
IRC Standards Review Committee	(1) FAC-010: There is still a "Cascading outages" in R2.2, and a couple of places where the word "Outages" has been deleted but the letter "o" is still there. (2) FAC-011: A footnote 2 is referenced in R2.3 but we are unable to find it
Response: The word, "outages" was removed from R2.2 and the two extra "o's" in the WECC Regional Variance have been removed. The reference to the footnote was a typographical error and has been removed.	
Salt River Project	FAC-010-2 R2.2 and R2.5 use the capitalized word "Cascading". This appears to be a typo; perhaps "Cascading Outages" was intended or was "cascading" not meant to be capitalized?FAC-011-2 R2.2 uses the capitalized word "Cascading". This appears to be a typo; perhaps "Cascading Outages" was

	intended or was "cascading" not meant to be capitalized?
Response: The word, "Cascading" is a defined term in the approved NERC Glossary of Terms Used in Reliability Standards, thus it is capitalized.	
SERC OC Standards Review Group	None of the requirements in FAC-10, 011 or 014 have VRS or time horizons identified. In FAC-011, R 2.3.2, the following language that was previously removed has been reinserted - "e.g., load greater than studied" - and should be removed. In FAC-010, Requirement 2.2, the word "outages" should be deleted - it is not a part of the definition for "Cascading."
Response Making modifications to VRFs and Time Horizons is outside the scope of the SAR. The drafting team removed the example, "e.g., load greater than studied" from R2.3.2 as proposed. The word, "outages" was removed from R2.2 as noted.	
OPPD	In FAC-010, the word "outages" still needs to be removed from R2.2, and the letter "o" needs to be removed from E1.2.2 and E1.3.1.
Response: The word, "outages" was removed from R2.2 as noted – and the extra "o" was removed from both E1.2.2 and E1.3.1.	
SPP Operating Reliability Working Group	In FAC-010, R2.2 and R2.5 and FAC-011, R2.2 cascading outages should not be capitalized indicating it is a defined term. In FAC-010, R2.3 a reference is made to Footnote 2 but the footnote is missing.In FAC-011, R2.3 remove the Footnote 2 since the footnote itself has been deleted.
Response: The word, "Cascading" is a defined term in the approved NERC Glossary of Terms Used in Reliability Standards, thus it is capitalized. The drafting team had intended to remove the word, "outage" from the standard – and in the final set of revisions, did remove the word, "outage" from R2.2. The erroneous reference to a footnote has been removed from R2.3 in both FAC-010 and FAC-011.	
FirstEnergy	1. Since the ATFN SDT is in the process of consolidating TPL-001 through TPL-004, it may help to revise FAC-010 R2.5 & R2.6 and FAC-011 R6 to be more general and remove specific reference to TPL-003. We suggest replacing the phrase "Reliability Standard TPL-003" with "the TPL series of reliability standards".
Response: NERC has already committed to modifying the FAC standards when the TPL standards are approved – we expect the implementation plan for the TPL standards to include specific changes to specific FAC standards – with a recommendation that the changes to the FAC standards become effective at the same time the changes to the TPL standards become effective.	
HydroOne Networks,	We noticed some change control/editorial errors that may have been

Inc.	overlooked. They include: FAC-010-2: R2.2 remove the word "outage" completely. FAC-010-2: R2.3 remove the reference to the second footnote after the word "following" FAC-011-2: R2.3 remove the reference to the second footnote after the word "acceptable" FAC-011-2: R2.3.2 remove "e.g., load greater than studied" as stated in the Consideration for Comments for Version 1 of the SAR As well, Violatin Risk Factors and Time Horizons need to be established and reviewed for these standards.
FAC-010-2: R2.2 - The word, "outages" was removed from R2.2 as noted. FAC-010-2: R2.3 and FAC-011-2: R2.3 – the erroneous references to footnotes were removed as noted. FAC-011-2: R2.3.2 - The drafting team removed the example, "e.g., load greater than studied" from R2.3.2 as proposed. Making modifications to VRFs and Time Horizons is outside the scope of the SAR.	
ATC	Comments on the SAR: Issue 1: The SAR states that the phrase "i.e. load greater than studied" in FAC-011-1 R2.3.2 will be deleted but this was not shown in either the red-line or clean version of the standard. Is is still the intention of the SDT to removed this phase? Issue 2: NERC's BOT has already overturn their earlier approval for the term "Cascading Outage". The following Statement appears in NERC's Glossary of Terms: "On December 27, 2007, the FERC remanded the definition of "Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustee withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FAC standards drafting team and the revised standards that are developed through the standards development process. Therefore, the definition is no longer in effect.

	With the NERC BOT withdraw of their prior approval and the FERC remand ATC does not believe that the SAR needs to address this definition. The only thing that the SAR must address is the term "Cascading Outage" is used in FAC-010, FAC-011 and FAC-014. Why does the SDT believe that they have to address a definition issue when both NERC BOT and FERC have not approve the definition? Question on what will be replacing the term "Cascading Outage": In FAC-010-1 Requirement 2.2 (redline version) the SDT is proposing to replace term "Cascading Outage" with the phrase "Cascading outage" but in requirement 2.5 the SDT is replacing it with only the term "Cascading". Is it the intention of the SDT to replace the term "Cascading Outages" with the phrase "Cascading outages" or only with the term "Cascading"? It's ATC's preference that the term "Cascading Outages" be replaced with the term "Cascading".

Response:

The phrase, "load greater than studied" has now been removed from both FAC-010 and FAC-011.

The BOT is waiting for the drafting team to bring them evidence that stakeholders approve the removal of the term, "Cascading Outages."

The term, "Cascading Outages" has been replaced throughout FAC-010 and FAC-011 with the term, "Cascading".

Standard Authorization Request Form

Title of Proposed Standard	Modifications to FAC-010-1 and FAC-011-1
Request Date	January 11, 2008
Modified Data	March 24, 2008

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)
Name Paul Johnson for Facility Ratings SDT	☐	New Standard
Primary Contact Paul Johnson	☒	Revision to existing Standard FAC-010-1 — System Operating Limits Methodology for the Planning Horizon FAC-011-1 — System Operating Limits Methodology for the Operations Horizon FAC-014-1 —
Telephone 614-716-6690 Fax	☐	Withdrawal of existing Standard
E-mail pbjohnson@aep.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The revisions are needed to eliminate the ambiguity identified by FERC in the approved standards and in the definition of Cascading Outage.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The regulatory approved version of FAC-010-1 will become effective on July 1, 2008 and set of the clarifications should be made before that time.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

In FERC Order 705, the Commission directed NERC to make the following modifications:

FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied”

In addition, the Commission remanded the definition of “Cascading Outage” and this term

should be withdrawn from the NERC Glossary of Reliability Terms. “Levels of Non-compliance” should be removed and replaced with new “Violation Severity Levels”. Update the standard to include the VRFs that were approved or modified in accordance with FERC Order 705.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) In FERC Order 705, the Commission directed NERC to make the following modifications: ▪ FAC-011-1 Requirement R2.3.2 – eliminate the phrase, “load greater than studied” In addition, the Commission remanded the definition of “Cascading Outage” and this term should be retired from the NERC Glossary of Terms Used in Reliability Standards, and the standards should be updated to use the defined term, “Cascading”. The “Levels of Non-compliance” should be removed and replaced with new “Violation Severity Levels”.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Authority	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	The Regional Variances within FAC-010 and FAC-011 need to be updated to include Violation Severity Levels to comply with FERC Order 705.

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

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A. Introduction

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2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

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R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

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R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~outages~~ or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

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R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

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R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

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R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

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R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

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D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

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The Performance-Reset Period shall be twelve months from the last non-compliance.

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The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

~~2.~~

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

~~4.~~3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of ~~three~~ four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One ~~or~~ of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more,

Requirement	Lower	Moderate	High	Severe
			issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~o~~ does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading ~~o~~ does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Proposed Action Plan and Description of Current Draft:

Third draft of Standard posted for pre-ballot review, subject to Standards Committee approval.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Reliability Coordinator
5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of four or more of the following:

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.

Requirement	Lower	Moderate	High	Severe
			of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.

Requirement	Lower	Moderate	High	Severe
			OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

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This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable~~[2]~~:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied.~~

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in ~~either~~ the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of ~~three~~ four or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One ~~or~~ of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or

Requirement	Lower	Moderate	High	Severe
	60 calendar days.	calendar days.	calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading~~-~~ does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

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None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLsfor the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

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2. **Number:** FAC-014-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Planning Authority
   - **4.3.** Transmission Planner
   - **4.4.** Transmission Operator
5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLsfor the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs **(including the subset of SOLs that are IROLs)** to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 ~~Changed "Cascading Outage" to "Cascading"~~ Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Two Ballot Pools and Pre-ballot Windows Open
May 2–June 2, 2008

Now available at: https://standards.nerc.net/BallotPool.aspx

Ballot Pool and Pre-ballot Window for FAC-010-2, FAC-011-2, FAC-014-2 Open May 2, 2008

The following standards are posted for a 30-day pre-ballot review starting May 2, 2008:

FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
FAC-014-2 — Establish and Communicate System Operating Limits

In Order 705, FERC approved these three standards and directed NERC to make changes to each of these standards. The changes fall into two categories – those that are subject to stakeholder input and those that are not subject to stakeholder input. The changes made to the above three standards were limited to addressing the directives in Order 705 that are subject to stakeholder input – retiring a definition; removing an example from a requirement; and adding Violation Severity Levels.

A new ballot pool to vote on the modifications to these three standards has been formed and will remain open up until 8 a.m. (EDT) Monday, June 2, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their 'ballot pool list server'. (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-FAC-Order_705_in@nerc.com

The ballot pool will remain open up until **8 a.m. (EDT) June 2, 2008**.

For assistance in using a list server, contact Barbara Bogenrief at 609-452-8060.

Ballot Pool and Pre-ballot Window for Interpretation of EOP-002-2 Requirement R6.3 and Requirement R7.1 for Brookfield Power Open May 2, 2008

An Interpretation of EOP-002-2 — Capacity and Energy Emergencies Requirement R6.3 and Requirement R7.1 for Brookfield Power is posted for a 30-day pre-ballot review starting May 2, 2008.

Brookfield Power submitted a Request for an Interpretation of EOP-002-2 — Capacity and Energy Emergencies. The request asked for clarification about the treatment of export transactions during emergency operations.

The request for interpretation asked if, to assist in complying with Control Performance and Disturbance Control Standards, Requirement R6.3 requires curtailment of non-firm exports when interruptible load is curtailed while R7.1 requires curtailment of firm exports when firm load is curtailed.

The interpretation clarifies that when considering actions to be taken to comply with EOP-002-2 Requirement R6.3, it is intended that all exports, firm and non-firm, are available for curtailment with the exception of those exports designated as network resources for an external Balancing Authority. If a capacity or energy emergency still exists after all exports have been curtailed with the exception of those related to a network resource designated to an external Balancing Authority, then EOP-002-2 Requirement R7.1 would take effect and firm load would be shed while the designated network resource transaction would continue to flow.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EDT) Monday, June 2, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their 'ballot pool list server'. (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-bp_interpret_eop-002a_in@nerc.com

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan
FAC-010-2, FAC-011-2, FAC-014-2

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards

FAC-010-1, FAC-011-1 and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards

Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date

The proposed effective dates are the same for all regulatory jurisdictions:

- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008
- FAC-014-2 will become effective on January 1, 2009

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Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Proposed Action Plan and Description of Current Draft:

Third draft of Standard posted for pre-ballot review, subject to Standards Committee approval.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot	June 2–11, 2008
3. Post response to comments on initial ballot	June 13, 2008
4. Conduct recirculation ballot	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Planning Authority
5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Proposed Action Plan and Description of Current Draft:

Third draft of Standard posted for pre-ballot review, subject to Standards Committee approval.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~outages~~ or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following~~[2]~~:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

~~2.~~

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

~~4.~~3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of ~~three~~ four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One ~~or~~ of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more,

Requirement	Lower	Moderate	High	Severe
			issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~o~~ does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading ~~o~~ does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

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This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Reliability Coordinator
5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of four or more of the following:

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.

Requirement	Lower	Moderate	High	Severe
			of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.

Requirement	Lower	Moderate	High	Severe
			OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

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4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None:

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Reliability Coordinator
5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable~~2~~:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied.~~

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in ~~either~~ the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of ~~three~~ four or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One ~~or~~ of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or

Requirement	Lower	Moderate	High	Severe
	60 calendar days.	calendar days.	calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading~~-~~ does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

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None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLsfor the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011 and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Proposed Action Plan and Description of Current Draft:

Third draft of Standard posted for pre-ballot review, subject to Standards Committee approval.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day pre-ballot period.	May 2–31, 2008
2. Conduct initial ballot.	June 2–11, 2008
3. Post response to comments on initial ballot.	June 13, 2008
4. Conduct recirculation ballot.	June 13–22, 2008
5. Board adoption.	June 26, 2008
6. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLsfor the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs **(including the subset of SOLs that are IROLs)** to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs **(including the subset of SOLs that are IROLs)** to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 ~~Changed "Cascading Outage" to "Cascading"~~ Replaced Levels of Non-compliance with Violation Severity Levels	Revised

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Standards Announcement

Initial Ballot Windows for Project 2008-04 and Project 2008-07 Now Open
June 2–11, 2008

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Ballot Window for Project 2008-04 - Modifications to FAC-010-2, FAC-011-2, and FAC-014-2 for Order 705 is Open

The **initial ballot** for the revisions to the following **FAC standards** (Project 2008-04) is open and will remain open until 8 p.m. on Wednesday, June 11, 2008:

FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
FAC-014-2 — Establish and Communicate System Operating Limits

In **Order 705**, FERC approved these three standards and directed NERC to make changes to each of these standards. The changes fall into two categories — those that are subject to stakeholder input and those that are not subject to stakeholder input. The changes made to the above three standards were limited to addressing the directives in Order 705 that are subject to stakeholder input — retiring a definition; removing an example from a requirement; and adding Violation Severity Levels.

> Note that in the version of FAC-011-2 that was posted for pre-ballot review, there was an error in the initial sentence of the Severe Violation Severity Level for Requirement R3 that has now been corrected as follows:
>
> > The Reliability Coordinator has a methodology for determining SOLs that is missing a description of ~~three~~ four or more of the following: R3.1 through R3.7.

Note that the drafts of both FAC-010-2 and FAC-011-2 that were posted for stakeholder comment from March 31 through April 29, 2008 included this error. Stakeholders submitted comments pointing out this error in both standards, and the drafting team's response indicated it would correct the error in both standards; however, the version of FAC-011-2 that was posted for pre-ballot review did not reflect the correction.

Ballot Window for Project 2008-07 — Interpretation of EOP-002-2 — Capacity and Energy Emergencies Requirements 6.3 and 7.1 for Brookfield Power is Open

The **initial ballot** for the **interpretation (for Brookfield Power)** of EOP-002-2 — Capacity and Energy Emergencies Requirements R6.3 and R7.1 is open and will remain open until 8 p.m. on Wednesday, June 11, 2008.

The request asked for clarification about the treatment of export transactions during emergency operations. Specifically, the request for interpretation asked if, to assist in complying with Control Performance and

Disturbance Control Standards, Requirement R6.3 requires curtailment of non-firm exports when interruptible load is curtailed while R7.1 requires curtailment of firm exports when firm load is curtailed.

The **interpretation** clarifies that when considering actions to be taken to comply with EOP-002-2 Requirement R6.3, it is intended that all exports, firm and non-firm, are available for curtailment with the exception of those exports designated as network resources for an external Balancing Authority. If a capacity or energy emergency still exists after all exports have been curtailed with the exception of those related to a network resource designated to an external Balancing Authority, then EOP-002-2 Requirement R7.1 would take effect and firm load would be shed while the designated network resource transaction would continue to flow.

Standards Development Process

The ***Reliability Standards Development Procedure Manual*** contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan
FAC-010-2, FAC-011-2, FAC-014-2

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards

FAC-010-1, FAC-011-1 and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards

Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date

The proposed effective dates are the same for all regulatory jurisdictions:

- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008
- FAC-014-2 will become effective on January 1, 2009

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Standards Announcement

Initial Ballot Results for Project 2008-04 and Project 2008-07

Now available at: https://standards.nerc.net/Ballots.aspx

Initial Ballot Results for Project 2008-04 — Modifications to FAC-010-2, FAC-011-2, and FAC-014-2 for Order 705

The initial ballot for the revisions to the following FAC standards (Project 2008-04) was conducted from June 2–11, 2008.

FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
FAC-014-2 — Establish and Communicate System Operating Limits

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the standards need modification before proceeding to a recirculation ballot. The drafting team will be reviewing all comments submitted with the initial ballots and will prepare its consideration of those comments. (Detailed Ballot Results)

Quorum: 88.83 %
Approval: 95.43 %

Initial Ballot Results for Project 2008-07 — Interpretation of EOP-002-2 — Capacity and Energy Emergencies Requirements 6.3 and 7.1 for Brookfield Power

The initial ballot for the interpretation (for Brookfield Power) of EOP-002-2 — Capacity and Energy Emergencies Requirements R6.3 and R7.1 was conducted from June 2–11, 2008.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the standards need modification before proceeding to a recirculation ballot. The drafting team will be reviewing all comments submitted with the initial ballots and will prepare its consideration of those comments. (Detailed Ballot Results)

Quorum: 89.67 %
Approval: 76.47 %

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long,
Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Ballot Results	
Ballot Name:	FAC-010_FAC-011_FAC-014_Order_705_in
Ballot Period:	6/2/2008 - 6/11/2008
Ballot Type:	Initial
Total # Votes:	167
Total Ballot Pool:	188
Quorum:	88.83 % The Quorum has been reached
Weighted Segment Vote:	95.43 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	59	1	52	0.945	3	0.055	1	3
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	45	1	33	0.943	2	0.057	3	7
4 - Segment 4.	8	0.6	6	0.6	0	0	1	1
5 - Segment 5.	32	1	24	0.96	1	0.04	1	6
6 - Segment 6.	20	1	16	0.941	1	0.059	1	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	9	0.8	7	0.7	1	0.1	0	1
Totals	**188**	**6.8**	**152**	**6.489**	**8**	**0.311**	**7**	**21**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	
1	Consolidated Edison Co. of New	Edwin E. Thompson PE	Affirmative	

	York			
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Julien Gagnon	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	View
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	lorees Tadros		
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Transmission Agency of Northern California	James W Beck	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	

2	California ISO	David Hawkins		
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services Company	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner		
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	

3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	Ralph Anderson		
4	North Carolina Municipal Power Agency #1	Andrew Fusco	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer		
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	Orlando Utilities Commission	Richard Kinas	Affirmative	View
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Negative	View
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Consideration of Comments on Initial Ballot of Revisions to FAC-010, FAC-011, FAC-014 for Order 705

Summary Consideration: The drafting team did not make any modifications based on comments submitted with the initial ballot for the modifications to these three standards.

Some balloters proposed modifications to the standards that involve modifications outside the drafting team's control.
One balloter proposed modifying several sets of VSLs to treat each of the subrequirements as though they were of equal weight in contributing to the requirement. The drafting team gave serious consideration to the contribution of each subrequirement in achieving the objective of the associated requirement – and the team does not believe that all subrequirements are of equal weight. For example, if the Planning Authority is required to have a methodology for developing SOLs, and the methodology that is developed is not suitable for use in the planning horizon, then the methodology can't be used for its intended purpose – and the intent of the requirement has been totally missed, which meets the criteria for a "Severe" Violation Severity Level. If the VSLs were modified as proposed, missing this subrequirement would be classified as a "Lower" Violation Severity Level.

One balloter suggested that the proposed dates in the implementation plan for the Version 2 standards could be confusing as entities wouldn't know which requirements to comply with. The drafting team noted that there will only be one standard in place at a time, and since the requirements in the proposed standards are the same as those in the already approved "Version 1" standards, it should not be difficult to know what performance is required.

One balloter proposed changes to improve the readability or to move some of the VSLs from one category to another. The drafting team did not make any of these changes as they do not seem warranted based on the high level of approval achieved during the initial ballot.

Two balloters highlighted typographical errors in the posted versions of the standards, and these will be corrected and noted before the recirculation ballot is conducted. These errors were in FAC-011-2 and include the following:

- R4 Severe VSL should reference the "Reliability Coordinator" rather than the "Planning Authority."
- R4 Severe VSL should have the word, "OR" between the two paragraphs
- Footnote 1 should reference FAC-011, not FAC-010

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Segment:	3
Organization:	Duke Energy Carolina
Member:	Henry Ernst-Jr
Comment:	1)VSLs for FAC-010-2 - It's unclear what your VSL is if your methodology didn't address R2.1 and R2.2 2)VSLs for FAC-011-2 ▪ 2a-VSLs aren't aligned with the severity of the sub-requirements. Suggest moving the "Moderate" VSL language to "Lower" and make the "moderate" VSL "N/A". "High" VSL should apply for failing to address either R1.1 or R1.3. "Severe" VSL should apply only if the RC has no documented SOL Methodology. ▪ 2b-Under the "Severe" VSL for R4, the reference to "Planning Authority" should instead be to the "Reliability Coordinator". ▪ 2c-Under the "Severe" VSL for R4, there should be an "OR" after the first paragraph and before the last paragraph. 3)VSLs for FAC-014-2 ▪ 3a-"Severe" VSLs for R1 - R4 should have the following lead-in phrase added "No SOLs have been established for the Reliability Coordinator's Area, OR…" ▪ 3b-The "Moderate", "High" and "Severe" VSLs for R5 should identify that "the supporting information provided "by the Reliability Coordinator" with the IROLs does not address 5.1.4, 5.1.3, 5.1.1, 5.1.2" ▪ 3c-Entity references in R3 and R4 should be made consistent with the Functional Model definitions. 4)FAC-014-2 Requirement R5 is extremely confusing, since the RC, TO, PA and TP are all responsible for communicating SOLs and IROLs to each other and adjacent entities.
Response:	1 – The compliance enforcement authority has latitude in determining which VSL is most applicable to any given situation. It isn't practical to develop a set of VSLs that covers all possible findings of non-compliance. In the example provided, the compliance enforcement authority may determine that the entity's violation is either Moderate or High. 2a– The drafting team used the following philosophy when developing the VSLs for R1: ▪ If the methodology is not applicable for use in the operations horizon, then the Reliability Coordinator and Transmission Operator can't use it – therefore the intent of the requirement has not been met at all, and the violation is severe. ▪ The statement that Facility Ratings will be respected is intended to provide the facility owner with some assurance that the system operating limits developed in accordance with the methodology will not violate the ratings

	established by the owner. The Violation Severity Level Guidelines document developed by the VSL Drafting Team proposed that a violation that included at least one significant element within the requirement should be at least a "Moderate" VSL. 2b – You are correct, the reference should be to the Reliability Coordinator, not the Planning Coordinator – we will fix this before we conduct the recirculation ballot. 2c – You are correct, there should be an "OR" between the last two paragraphs of the Severe VSL for FAC-011-2 R4 – we will fix this before we conduct the recirculation ballot. 3a – There is always an SOL – at a minimum, the Facility Rating would be the SOL. 3b – The drafting team envisioned the situation where some of the supporting information was missing – note that the failure to address 5.1.4 is already covered in the "Moderate" VSL – failure to address 5.1.3 is covered in the "High" VSL – failure to address 5.1.1 and 5.1.2 are addressed in the "Severe" VSL. 3c – The drafting team made the fewest changes possible to this set of standards. The Functional Model Working Group has confirmed that the Planning Authority and Planning Coordinator are the same. When this set of standards was originally started, the term used in the Functional Model was, "Planning Authority." 4 – The drafting team did not modify R5. The original drafting team could not identify a way of simplifying the requirement without duplicating much of the information several times. While the requirement is complex, the drafting team believes that each responsible entity can comprehend the portions of the requirement that are applicable.
Segment:	1, 3, 5, 6
Organization:	Manitoba Hydro
Member:	Michelle Rheault, Ronald Dacombe, Mark Aikens, Daniel Prowse
Comment:	MH does not see a reliability need to define SOLs in the planning horizon and believes the Standard FAC-010 should be withdrawn. As Operators do not use SOLs developed for the planning horizon in real time operations there is no benefit from the extra work required to comply with this standard. Accordingly, MH believes Standard FAC-014 should be modified to only require the establishment and communication of SOLs in the operating horizon (ie. remove Transmission Planner and planning authority from the Applicability section, remove Requirements R3, R4, R5.3, R5.4 and R6 and remove Planning Authority from the Measures section). The VSLs are unrealistic for SOLs in the planning horizon and consequently, FAC-010 and the planning requirements for FAC-014 cannot be supported.
Response:	The ballot for this set of standards is for the modifications that were made to address some of the directives in FERC Order 705. The need for SOLs for use in the planning horizon was established with stakeholders during the initial development of this set of standards.

	Without additional details, the drafting team cannot address your concern about the VSLs being unrealistic. The drafting team developed the VSLs using the VSL Guidelines Criteria. The VSLs categorize the degree to which the performance that was assessed missed being fully compliant, with the "Lower" VSL describing performance that is close to being fully compliant, and the "Severe" VSL describing performance that mostly or totally misses achieving the intent of the requirement.
Segment:	1
Organization:	New York State Electric & Gas Corp.
Member:	Henry G. Masti
Comment:	I think there may be a typo in footnote #1 on FAC 011? " The Contingencies identified in FAC-010[FAC-010 should be FAC-011??] R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied." thanks hgm
Response:	You are correct, the reference in the footnote should be to "FAC-011" – we will fix this before we conduct the recirculation ballot.
Segment:	3
Organization:	Ameren Services Company
Member:	Mark Peters
Comment:	Applicable to all: 1. The red-line changes are an improvement to the earlier drafts, but it is still not clear how any of these standards are going to ensure reliability. If the real purpose behind these standards is to better align planning and operating, it appears the drafting team has again has missed the mark. With two entities, the PA and RC, developing separate SOL methodologies, there is the potential for conflict, inconsistency, and no coordination. 2. We continue to struggle with the concept of operating limits in the planning horizon and the need for multiple types of studies to satisfy the TPL-001 through 004 standards and the FAC-010, 011, and 014 standards. Yes, there are system limits in planning studies, but they are not operating limits. Violations of the TPL performance standards would require a corrective plan for a system upgrade, topology change, operating procedure, etc. to meet compliance requirements. Does this mean that every TPL violation would result in an SOL? Perhaps, but these are not the only limits that need to be recognized and many of the limits would be fixed before they are observed in the operating horizon. The SOL methodology needs to recognize both NERC reliability standards and local planning criteria.

	3. Operating personnel need to be aware of the fast acting multiple contingencies that do not allow time for system operators to react including Table 1 Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, in addition to their planning for the next single contingency. FAC-010-2 1. In R2.1, "steady-state stability" needs to be included in the second line to ensure that oscillations are well damped. Also, at what transfer levels must the system meet the performance standards and who determines what level is too much? The TPL standards only specify those levels to cover the net scheduled interchange (base case). In operations, a wider envelope of transfer capability needs to be recognized to cover imports, exports, and extreme system bias conditions based on FCITC analyses. Incremental transfer capability should be included in the SOL methodologies. 2. In R2.2, the specific types of contingencies that should be considered in the methodology are identified. Why not include a reference to TPL-002-0 and Table 1 similar to what is included in R2.5? In the event that standards TPL-001 through 004 are revised, the contingencies listed in FAC-010 need to follow the revision. 3. As written, FAC-010-2 is applicable to the Planning Authority. Has the PA performed any of the studies to support the TPL standards? Has the PA performed any incremental transfer capability analysis? Has the PA recognized and honored local area planning criteria? If not, where is the PA going to get its information to develop its SOL methodology for FAC-010? We do not believe that the PA can adequately provide such a methodology unilaterally. FAC-011-2 1. What on-line stability tools are being employed to demonstrate stability for R2.1 and R2.2? 2. What is the pre-contingency state in the operating horizon, and why do they bother to study those conditions? There is always something broke and/or out of service in the operating horizon. Shouldn't the pre-contingency state be reclassified as the operating state? The operating state should then have to meet the conditions of all loadings within normal ratings and all voltages within limits and be able to handle the next contingency. 3. Why is there no requirement for establishing SOLs for operating conditions with two contingencies as required in TPL-003-1 or FAC-010-2? This appears to be another inconsistency between planning and operating. FAC-014-2

	1. Does this standard achieve its purpose? Other than the auditors, who checks the SOLs developed by the TP and TOP to see that they are consistent with the methodologies of the PA and RC? How is it determined that all of the SOLs are identified? How does this contribute to reliability or is this just another item to be audited? 2. Both the TOP and the TP are each establishing SOL in R2 and R4 based on the methodologies of the RC and PA, respectively. The TOP has to follow the RC methodology and the TP has to follow the PA methodology. Are these methodologies consistent? Who provides/ensures coordination between entities?
Response:	This ballot is for the modifications made to the three standards to comply with some of the directives in FERC Order 705. Those modifications are limited to the red line changes that were posted for review. None of the comments provided address the modifications that are the subject of the ballot. If the balloter believes that the set of standards need wholesale revision, the balloter can submit a SAR with a proposal for revisions.
Segment:	5
Organization:	Orlando Utilities Commission
Member:	Richard Kinas
Comment:	FAC-010 requirement 2.3 - no requirement should ever have the word "may" in it - may is a suggestion not a requirement VSL should be clearer, as an example Moderate VLS for R2 is: Presented: The Planning Authority’s SOL Methodology requires that SOLs are set to meet BES performance in the precontingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6) Recommended: Entity did not completely address one or more of the following: R2.5, R2.6
Response:	This ballot is for the modifications made to the three standards to comply with some of the directives in FERC Order 705. Those modifications are limited to the red line changes that were posted for review. The drafting team agrees that the language in the VSLs could be simplified – however in their current state they are understandable and seem to be supported by most balloters – so no changes were made.
Segment:	1
Organization:	American Transmission Company, LLC
Member:	Jason Shaver
Comment:	ATC is balloting negative on these standards in order to have the SDT address our concerns with the implementation schedule. The SDT needs to clarify the retirement dates of the three existing version 1 standards. (FAC-010-1, FAC-011-1 and FAC-014-1 see implementation plan)

	Per the implementation plan the existing standards will not be retired until the proposed new standard become effective. (FAC-010-2 eff. July 1, 2008, FAC-011-2 eff. Oct. 1, 2008, and FAC-014-2 eff. Jan. 1, 2009) FAC-010 This standard is scheduled to be effective on July 1, 2008 and it is very likely that the version 2 will not be approved by FERC before the July 1 effective date. Therefore the version 2 standard should become effective 30 day's following FERC approval to allow for any modifications to documents and distribution. The version 1 standard should be retired on the same day that version 2 standard becomes mandatory and enforceable. ATC is concerned that the proposed effective date will be back dated when version 2 is approved by the BOT and FERC and potentially making entities non-compliant. FAC-011 and FAC-014 It is very likely that the NERC BOT and FERC will approve the version 2 standard before the October 1 and January 1 effective dates but until FERC approves the standard the RC has to start working on compliance to the version 1s. It seems that the SDT is confusion the retirement date of the version 1 standards with the effective date of the version 2 standards. Version 1 standards need to be retired immediately following FERC approval so that the version 2s can become effective on October 1 2008 and January 1, 2009. NOTE: For those entities that do not report to FERC the version one standards should be retired immediately following the NERC BOT approval of the version 2 standards. Since FAC-010-1 is scheduled to be effective on July 1 these entities should be given an additional 30 days to become compliant with FAC-010-2.
Response:	The drafting team selected retirement dates that coincide with the effective dates already approved by FERC so that there will only be one version of each standard in effect at any point in time. Since the Commission directed NERC to submit the VSLs for the standards before the standards become effective, we believe that the Commission will act quickly to approve the revisions to the already approved versions of the standards. To meet the administrative needs of the compliance program, new or revised standards will become effective on the first day of a calendar quarter. Therefore, the team cannot support the proposal to modify the effective date for FAC-010 as proposed. The implementation plan is clear that the already approved standards will be retired when the new versions of the standards become effective. Version 2 of FAC-010, FAC-011, and FAC-014 do not contain any new requirements that weren’t also included in the first version of these standards, so there should not be any issues associated with compliance to the requirements. If an entity were compliant with Version 1 of FAC-010, FAC-011, FAC-014, that entity should also be compliant with Version 2 of those same standards.

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Segment:	10
Organization:	Southwest Power Pool
Member:	Charles H. Yeung
Comment:	SPP's ORWG submitted comments regarding the VSLs for these standards. Because many of those recommendations were not incorporated, SPP cannot support the proposed FAC 010,011, and 014 standards. We reiterate the numerous outstanding concerns here. FAC-010-2: R1 - Clarify which subrequirement is more critical by revising to: "The PA has a documented SOL Methodology but is missing one of the subrequirements. Assign to the Lower category. Substitute two subrequirements for one and assign a Moderate category. And substitute three subrequirements for one and assign a Higher category." Also remove the first paragraph (above the 'or') in the Severe category. R2 - reword the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another. R4 - these VSLs add an additional requirement to R4 by stipulating a specific time reference for the requirement. Eliminate the timing aspects and revise the VSLs to parallel what we propose for the VSLs for R1. R5 - delete the phrase '…but less than 60 calendar days.' from the Lower VSL. Recommend the following language for the Moderate category: 'The Planning Authority in their response did not include statements regarding changes or no changes to their SOL methodology.' Delete the first paragraph (above the 'or') of the VSL in the Higher category and keep the second paragraph (below the 'or'). Replace the entire Severe category to the following: 'The Planning Authority failed to respond.' FAC-011-2: R1 - Clarify which subrequirement is more critical by revising to: "The PA has a documented SOL Methodology but is missing one of the subrequirements. Assign to the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Finally, substitute three subrequirements for one and assign a Higher category." Also, remove the first paragraph (above the 'or') in the Severe category. R2 - reword the VSLs to make them similar to the VSLs for R3. As written, the VSLs imply that one of the subrequirements is more important than another.

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	The VSLs for R4 add an additional requirement to R4 by stipulating a specific time reference for the requirement. Eliminate the timing aspects and revise the VSLs to parallel what we proposed for the VSLs for R1. Change the VSLs for R5 to match those we proposed in R5 of FAC-010 except replace Planning Authority with Reliability Coordinator. FAC-014: The VSLs for R5 introduce a specific timing requirement that is not included in R5. This should be deleted. R5 - Clarify which of the subrequirements is more critical than the other. We recommend the VSLs be revised to the following: "The responsible entity has communicated its SOL Methodology but is missing one of the subrequirements. This would be assigned the Lower category. Then, substitute two subrequirements for one and assign a Moderate category. Substitute three subrequirements for one and assign a Higher category. Finally, substiture four subrequirements for one and assign a Severe category." R6 - move the Higher category VSL to the empty Moderate category. Move the second paragraph of the Severe category to the Higher category. Leave the first paragraph of the Severe category as the only entry for the Severe category. In addition, SPP supports the comment on FAC-014 R6 submitted by the IRC Standards Review Committee and is concerned with the the SDT response: "The intent of Requirement R6 is not for the Planning Coordinator to identify the stability-related limits – the intent of this requirement is to deliver these limits to the Reliability Coordinator. If the Planning Coordinator develops the stability-related limits but never delivers them to the Reliability Coordinator, then the Reliability Coordinator does not have the limits to use in its real-time operation and the intent of the requirement is not met at all." If the PC fails to identify the multiple contingencies associated with the stability limit, it should weigh much higher than a failure to provide the list and the limit to more than one RC (note that the VSL is Severe for failing either condition, hence the SRC's original comment to disagree with the proposed VSLs). The SDT's rationale that not delivering the information to the RC would leave the RC without limits for use in real-time operation is flawed. RCs develop limits themselves, and according to the FAC standards, would take the multiple contingencies identified by the PC, or use its own, in a limit calculation.
Response:	FAC-010-2: VSLs for R1 – The drafting team does not agree with the proposed modification as the subrequirements are not of equal weight – for example, if the methodology is not applicable for use in the planning horizon, the product fails to meet the intent of the requirement – and this qualifies as a Severe VSL. Under the VSL proposed, this would be a “Lower” VSL.

	VSLs for R2 - The drafting team does not agree with the proposed modification as the subrequirements are not of equal weight – a methodology that doesn't address the most frequently occurring types of contingencies (single contingencies) is less useful than a methodology that doesn't address the pre-contingency state. VSLs for R4 - The requirement states that the distribution must take place, "prior to the effectiveness of the change". This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place before the change, but did take place, there is a category of VSL to capture the noncompliant performance. VSLs for R5 - The drafting team considered using the phrase, "The Planning Authority failed to respond" but envisioned the situation where the auditor requests evidence of a response, and the entity claims that the response is under development but hasn't been completed and delivered – the outer boundary of 90 calendar days was intended to clarify that if the response hasn't been provided within 90 days, then it can be considered to have not been provided. FAC-011-2: VSLs for R1 - The drafting team does not agree with the proposed modification as the subrequirements are not of equal weight – for example, if the methodology is not applicable for use in the operations horizon, the product fails to meet the intent of the requirement – and this qualifies as a Severe VSL. Under the VSL proposed, this would be a "Lower" VSL. VSLs for R2 - The drafting team does not agree with the proposed modification as the subrequirements are not of equal weight – a methodology that doesn't address the most frequently occurring types of contingencies (single contingencies) is less useful than a methodology that doesn't address the pre-contingency state. VSLs for R4 - The requirement states that the distribution must take place, "prior to the effectiveness of the change". This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place before the change, but did take place, there is a category of VSL to capture the noncompliant performance. VSLs for R5 - The drafting team considered using the phrase, "The Reliability Coordinator failed to respond" but envisioned the situation where the auditor requests evidence of a response, and the entity claims that the response is under development but hasn't been completed and delivered – the outer boundary of 90 calendar days was intended to clarify that if the response hasn't been provided within 90 days, then it can be considered to have not been provided. FAC-014 VSLs for R5 - The requirement states that the entity requesting the limits must deliver limits to those entities that request

	them and provide a "a schedule for delivery of those limits." The measure requires evidence that the limits were delivered as requested. This is a "timing" component that was carried over to the VSLs so that if the distribution hasn't taken place "as scheduled," but did take place, there is a category of VSL to capture the noncompliant performance. The drafting team does not agree with the proposed modification as the subrequirements are not of equal weight – providing the IROL T_v contributes more to meeting the intent of the requirement than providing the type of limitation represented by the IROL. VSLs for R6 – The drafting team did not adopt the proposed modifications. The balloter has provided no justification for the proposed modifications. The drafting team continues to believe that if the Planning Authority fails to distribute the stability-related limits to a Reliability Coordinator, then a serious aspect of the requirement has not been met, and warrants a , "High" VSL.

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

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[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

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Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

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Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21 – March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

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Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of Standard posted for recirculation ballot review.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period

Requirement	Lower	Moderate	High	Severe
	that was longer than 45 calendar days but less than 60 calendar days.	that was 60 calendar days or longer but less than 75 calendar days.	that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of Standard posted for recirculation ballot review.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

[1] The Contingencies identified in FAC-~~010~~ 011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The ~~Planning Authority~~Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
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R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete

Requirement	Lower	Moderate	High	Severe
	response in a time period that was longer than 45 calendar days but less than 60 calendar days.	response in a time period that was 60 calendar days or longer but less than 75 calendar days.	response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–11, 2008.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
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This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised

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Standards Announcement

Recirculation Ballot Opens

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot for Project 2008-04 — Modifications to FAC-010, FAC-011, and FAC-014 for Order 705 is Open

The recirculation ballot for the revisions to the following FAC standards (Project 2008-04) is open until 8 p.m. on Sunday, June 22, 2008.

FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
FAC-014-2 — Establish and Communicate System Operating Limits

In Order 705, FERC approved these three standards, and directed NERC to make changes to each of these standards. The changes fall into two categories — those that are subject to stakeholder input and those that are not subject to stakeholder input. The changes proposed are limited to addressing the directives in Order 705 that are subject to stakeholder input — retiring a definition; removing an example from a requirement; and adding Violation Severity Levels.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of initial ballot comments. The drafting team corrected three typographical errors in FAC-011-2 following the initial ballot and has posted both a clean and a redline version of the corrected standard. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long,
Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Implementation Plan
FAC-010-2, FAC-011-2, FAC-014-2

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards

FAC-010-1, FAC-011-1 and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards

Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date

The proposed effective dates are the same for all regulatory jurisdictions:

- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008
- FAC-014-2 will become effective on January 1, 2009

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Standards Announcement

Final Ballot Results for Project 2008-04

Now available at: https://standards.nerc.net/Ballots.aspx

Final Ballot Results for Project 2008-04 — Modifications to FAC-010-2, FAC-011-2, and FAC-014-2 for FERC Order 705

A recirculation ballot for the revisions to the following FAC standards (Project 2008-04) was conducted from June 13–22, 2008 and the revisions to the standards were approved.

FAC-010-2 — System Operating Limits Methodology for the Planning Horizon

FAC-011-2 — System Operating Limits Methodology for the Operations Horizon

FAC-014-2 — Establish and Communicate System Operating Limits

The Ballot Results standards web page provides a link to the detailed results for this ballot.

Quorum:	89.36%
Affirmative:	95.21 %

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Standards Administration

Registered Ballot Body
Ballot Events
Current Ballot Pools
Current Ballots
Previous Ballots
Vetting
Proxy Pool

Ballot Results	
Ballot Name:	FAC-010_FAC-011_FAC-014_Order_705_rc
Ballot Period:	6/13/2008 - 6/22/2008
Ballot Type:	recirculation
Total # Votes:	168
Total Ballot Pool:	188
Quorum:	**89.36 % The Quorum has been reached**
Weighted Segment Vote:	95.21 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	59	1	51	0.927	4	0.073	1	3
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	45	1	35	0.946	2	0.054	2	6
4 - Segment 4.	8	0.6	6	0.6	0	0	1	1
5 - Segment 5.	32	1	24	0.96	1	0.04	1	6
6 - Segment 6.	20	1	16	0.941	1	0.059	1	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	9	0.8	7	0.7	1	0.1	0	1
Totals	**188**	**6.8**	**153**	**6.474**	**9**	**0.326**	**6**	**20**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Julien Gagnon	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	

1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	View
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Iorees Tadros		
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Transmission Agency of Northern California	James W Beck	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins		
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services Company	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner		
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	

3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	Ralph Anderson		
4	North Carolina Municipal Power Agency #1	Andrew Fusco	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer		
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		

6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Negative	View
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

Improving Reliability and Security

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Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Planning Authority
5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

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[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

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Future Development Plan:

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Definitions of Terms Used in Standard

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None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period

Requirement	Lower	Moderate	High	Severe
	that was longer than 45 calendar days but less than 60 calendar days.	that was 60 calendar days or longer but less than 75 calendar days.	that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Initial ballot conducted from June 2–12, 2008

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of Standard posted for recirculation ballot review.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

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[1] The Contingencies identified in FAC-~~010~~ 011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator‘s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator’s SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The ~~Planning Authority~~Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete

Requirement	Lower	Moderate	High	Severe
	response in a time period that was longer than 45 calendar days but less than 60 calendar days.	response in a time period that was 60 calendar days or longer but less than 75 calendar days.	response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

   1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

   1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

   1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

   1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

   1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

   1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

   1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

   1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

   1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

   1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

   1.2.2 Cascading does not occur.

   1.2.3 Uncontrolled separation of the system does not occur.

   1.2.4 The system demonstrates transient, dynamic and voltage stability.

   1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned

removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised

Project 2008-04 — Revisions to FAC-010, FAC-011, and FAC-014

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR posted for comment with draft standard for 45-day comment period from January 21–March 5, 2008.

Second draft of SAR and proposed changes to standards posted for a 30-day comment period from March 31–April 29, 2008.

Posted for 30-day pre-ballot review from May 2–31, 2008.

Initial ballot conducted from June 2–11, 2008.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard, posted for recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	June 13, 2008
2. Conduct recirculation ballot.	June 13–22, 2008
3. Board adoption.	June 26, 2008
4. Submit to regulatory authorities for approval.	June 30, 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**
2. **Number:** FAC-014-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Planning Authority
   - **4.3.** Transmission Planner
   - **4.4.** Transmission Operator
5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**

   4.1. Planning Authority
5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
1	January 16, 2008	Changed effective date to July 1, 2008	Effective Date
2	June 23, 2008	Changed “Cascading Outage” to “Cascading” Capitalized, “Facilities” in R2.5 Replaced Levels of Non-compliance with Violation Severity Levels for the continent-wide portion of the standard Changed “Cascading Outages do” to “Cascading does” in 1.2.2 and 1.3.1 of the Regional Variance	Revision

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: **(To be replaced with VSLs once developed and approved by WECC)**

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period

Requirement	Lower	Moderate	High	Severe
	that was longer than 45 calendar days but less than 60 calendar days.	that was 60 calendar days or longer but less than 75 calendar days.	that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	January 16, 2008	Changed the effective date to October 1, 2008	Effective Date
2	June 23, 2008	Changed “Cascading Outage” to “Cascading” Deleted example, “e.g. load greater than studied” in R2.3.2 and added an “a)” and “b)” for improved clarity in this subrequirement Replaced Levels of Non-compliance with Violation Severity Levels for the continent-wide portion of the standard Corrected footnote 1 to reference FAC-011 rather than FAC-010 Changed “Cascading Outages do” to “Cascading does” in 1.2.2 and 1.3 of the Regional Variance	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	January 16, 2008	Changed Effective Date to January 1, 2009	Effective Date
1	March 12, 2008	Fixed typo in Effective Date from “January 1, 2008” to “January 1, 2009.”	Errata
2	June 23, 2008	Replaced Levels of Non-compliance with Violation Severity Levels	Revision

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The following definition should be retired from the NERC Glossary of Terms Used in Reliability Standards when this standard is approved:

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a predetermined area.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** July 1, 2008

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all ~~facilities~~ Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated

responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

~~2.~~ **Levels of Non-Compliance ~~(Does not apply to the~~ for Western Interconnection~~)~~**

~~2.1.~~ ~~**Level 1:** There shall~~**: (To be** ~~a level one non-compliance if either of the following conditions exists:~~

~~2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.~~

~~2.3. **Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the six required topics in R3.~~

2. ~~**Level 4:** The SOL Methodology was not issued to all required entities in accordance~~**replaced with** ~~R4.~~**VSLs once developed and approved by WECC)**

~~4. **Levels of Non-Compliance for Western Interconnection:**~~

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. **Violation Severity Levels:**

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that	The Planning Authority has a methodology for determining SOLs that is

Requirement	Lower	Moderate	High	Severe
	includes a description for all but one of the following: R3.1 through R3.6.	includes a description for all but two of the following: R3.1 through R3.6.	includes a description for all but three of the following: R3.1 through R3.6.	missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar

Requirement	Lower	Moderate	High	Severe
			and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.

R5	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~Outages do~~does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading ~~Outages do~~does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
1	January 16, 2008	Changed effective date to July 1, 2008	Effective Date
2	June 23, 2008	Changed "Cascading Outage" to "Cascading" Capitalized, "Facilities" in R2.5 Replaced Levels of Non-compliance with Violation Severity Levels for the continent-wide portion of the standard Changed "Cascading Outages do" to "Cascading does" in 1.2.2 and 1.3.1 of the Regional Variance	Revision

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** October 1, 2008

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading ~~Outages~~ or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-~~010~~011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or~~,~~ (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~, e.g., load greater than studied.~~

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

~~2.~~ Levels of Non-Compliance ~~**(Does not apply to the**~~ for Western Interconnection~~)~~

~~2.1.~~ ~~**Level 1:**~~ ~~There shall~~: **(To be** ~~a level one non-compliance if either of the following conditions exists:~~

~~2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

~~2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.~~

~~2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.~~

~~2.3. **Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the seven required topics in R3.~~

2. ~~**Level 4:** The SOL Methodology was not issued to all required entities in accordance~~**replaced with** ~~R4.~~**VSLs once developed and approved by WECC)**

~~**Levels of Non-Compliance for Western Interconnection:**~~

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. **Violation Severity Levels:**

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following:	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the

Requirement	Lower	Moderate	High	Severe
	R3.1 through R3.7.	R3.1 through R3.7.	R3.1 through R3.7.	following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness

Requirement	Lower	Moderate	High	Severe
			methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period

Requirement	Lower	Moderate	High	Severe
	that was longer than 45 calendar days but less than 60 calendar days.	that was 60 calendar days or longer but less than 75 calendar days.	that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading ~~Outages do~~does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of

contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading ~~Outages do~~does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	January 16, 2008	Changed the effective date to October 1, 2008	Effective Date
2	June 23, 2008	Changed “Cascading Outage” to “Cascading” Deleted example, “e.g. load greater than studied” in R2.3.2 and added an “a)” and “b)” for improved clarity in this subrequirement Replaced Levels of Non-compliance with Violation Severity Levels for the continent-wide portion of the standard Corrected footnote 1 to reference FAC-011 rather than FAC-010 Changed “Cascading Outages do” to “Cascading does” in 1.2.2 and 1.3 of the Regional Variance	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**

2. **Number:** FAC-014-~~1~~2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Transmission Operator

5. **Effective Date:** January 1, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2:** Not all SOLs were provided in accordance with their respective schedules.~~

~~**2.3. Level 3:** SOLs provided were not developed consistent with the SOL Methodology.~~

~~**2.4. Level 4:** There shall be a level four non-compliance if either of the following conditions exist:~~

~~**2.4.1** No SOLs were provided in accordance with their respective schedules.~~

~~**2.4.2** No evidence the Planning Authority delivered a set of stability-related multiple contingencies and their associated limits to Reliability Coordinators in accordance with R6.~~

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
R2	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
R3	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)
R4	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25%	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75%

Requirement	Lower	Moderate	High	Severe
	to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
R5	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

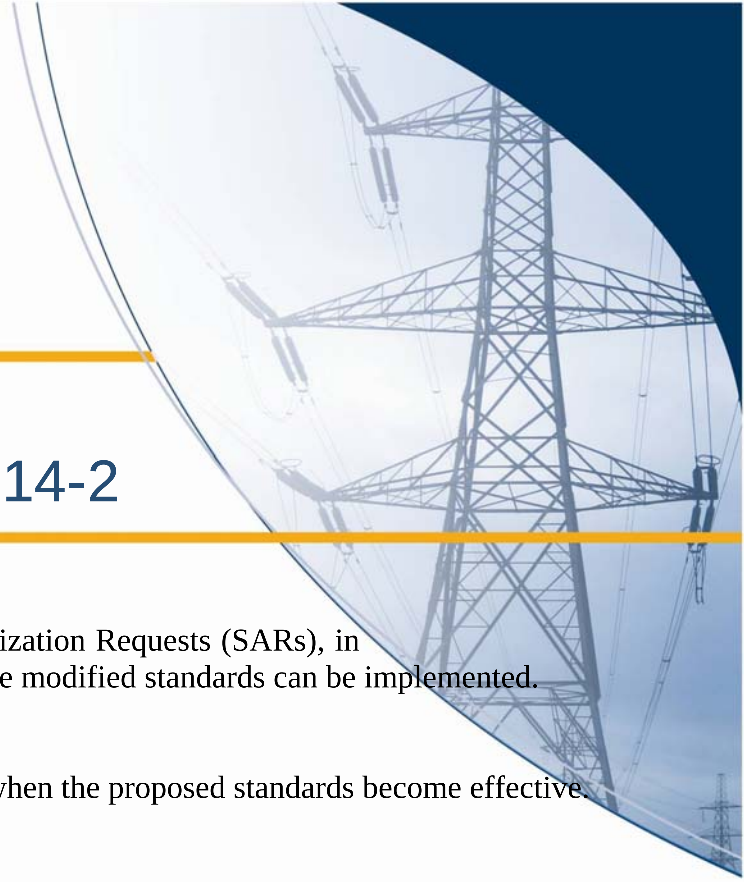
R6	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	January 16, 2008	Changed Effective Date to January 1, 2009	Effective Date
1	March 12, 2008	Fixed typo in Effective Date from “January 1, 2008” to “January 1, 2009.”	Errata
2	June 23, 2008	Replaced Levels of Non-compliance with Violation Severity Levels	Revision



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan
FAC-010-2, FAC-011-2, FAC-014-2

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these modified standards can be implemented.

Retire Associated Standards
FAC-010-1, FAC-011-1 and FAC-014-1 should be retired when the proposed standards become effective.

Compliance with Standards
Once these standards become effective, the responsible entities identified in the applicability section of the standard must comply with the requirements.

Proposed Effective Date
The proposed effective dates are the same for all regulatory jurisdictions:
- FAC-010-2 will become effective on July 1, 2008
- FAC-011-2 will become effective on October 1, 2008
- FAC-014-2 will become effective on January 1, 2009

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