Supporting Statement for
FERC-725D, Facilities Design, Connections and Maintenance Reliability Standards
As Proposed in Docket No. RM07-3-000
(A Final Rule Issued December 27, 2007)

The Federal Energy Regulatory Commission (Commission) (FERC) requests that the Office of Management and Budget (OMB) review and approve **FERC-725D, Mandatory Reliability Standards for Critical Infrastructure Protection**, for a three year period. FERC-725D (Control No. 1902-0247) is a new Commission data collection, (filing requirements), as contained in 18 Code of Federal Regulations, Part 40.

The Commission requests that OMB approve the projected estimates reported in this submission. The Commission's estimates are based on the potential number of entities who will have to come into compliance with the mandatory standards. The Commission did not receive any comments at the NOPR stage concerning these estimates and retains them for the Final Rule. However, as the ERO completes its registration process and as mandatory standards are updated and enforced; the Commission will revise these estimates for these requirements.

These Reliability Standards are approved by the Commission pursuant to its authority under section 215 of the Federal Power Act (FPA), which authorizes the Commission to approve a Reliability Standard proposed by the Electric Reliability Organization (ERO) if the Commission determines that it is just and reasonable, not unduly discriminatory or preferential and in the public interest. The Reliability Standards approved in this Final Rule are necessary for the reliable operation of the nation's interconnected Bulk-Power System.

Background

On August 8, 2005, the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005), was enacted into law.[1] EPAct 2005 added a new section 215 to the FPA, which requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or the Commission can independently enforce Reliability Standards.[2]

In the aftermath of the 1965 Blackout in the northeast United States, the electric industry established the North American Electric Reliability Council (NERC), a voluntary reliability organization. Since its inception, NERC has developed Operating Policies and Planning Standards that provide voluntary guidelines for operating and planning the North American bulk-power system. In April 2005, NERC adopted "Version O" reliability standards that translated the NERC Operating Policies, Planning Standards and compliance requirements into a

1 Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), 16 U.S.C. 824o.
2 16 U.S.C. 824o(e)(3).

comprehensible set of measurable standards. While NERC has developed a compliance enforcement program to ensure compliance with the reliability standards it developed, industry compliance has been voluntary and not subject to mandatory enforcement penalties. Although NERC's efforts have been important in maintaining the reliability of the nation's bulk-power system, NERC itself has recognized the need for mandatory, enforceable reliability standards and has been a proponent of legislation to establish a FERC-jurisdictional ERO that would propose and enforce mandatory reliability standards.

On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[3] In Order No. 672, the Commission certified one organization, NERC, as the ERO.[4] The Reliability Standards developed by the ERO and approved by the Commission will apply to users, owners and operators of the Bulk-Power System, as set forth in each Reliability Standard.

In accordance with section 215(d) (2) of the FPA and § 39.5(c) of the Commission's regulations, the Commission is required to give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard or to a Regional Entity organized on an Interconnection-wide basis with respect to a proposed Reliability Standard or a proposed modification to a Reliability Standard to be applicable within that Interconnection.[5]

The ERO must file with the Commission each new or modified Reliability Standard that it proposes to be made effective under section 215 of the FPA. The Commission can then approve or remand the Reliability Standard. The Commission also can, among other actions, direct the ERO to modify an approved Reliability Standard to address a specific matter if it considers this appropriate to carry out section 215 of the FPA.[6] Only Reliability Standards approved by the Commission will become mandatory and enforceable.

Each proposed Reliability Standard uses a common organizational format that includes five sections, as follows: (A) Introduction, which includes "Purpose" and "Applicability" sub-sections; (B) Requirements; (C) Measures; (D) Compliance; and (E) Regional Differences.

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On November 15, 2006, NERC filed 20 revised Reliability Standards and three new Reliability Standards for Commission approval. The Commission addressed the 20 revised Reliability Standards in Order No. 693.[7] The three new Reliability Standards were designated by NERC as follows:

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3 Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), order on reh'g, Order No. 672-A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

4 North American Electric Reliability Corp., 116 FERC ¶ 61,062 (ERO Certification Order), order on reh'g & compliance, 117 FERC ¶ 61,126 (ERO Rehearing Order) (2006), order on compliance, 118 FERC ¶ 61,030 (2007) (Jan. 2007 Compliance Order), appeal docket sub nom. Alcoa, Inc. v. FERC, No. 06-1426 (D.C. Cir. Dec. 29, 2006).

5 18 CFR 39.5(c)(1), to be codified at 16 U.S.C.824o.

6 Section 215(d)(5) of the FPA.

7 On March 16, 2007, the Commission approved 83 of the 107 standards initially filed by NERC. See Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 72 Fed. Reg., 16,416 (April 4, 2007), 118 FERC ¶ 61,218 (2007), *order on reh'g* Order No. 693-A, 120 FERC ¶ 61,053 (2007).

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).

The three FAC Reliability Standards, designated FAC-010-1, FAC-011-1 and FAC-014-1, require planning authorities and reliability coordinators to establish methodologies to determine system operating limits (SOLs) for the Bulk-Power System in the planning and operation horizons. In addition, NERC proposed the addition or revision of the following terms in the NERC Glossary of Terms Used in Reliability Standards (NERC glossary): "cascading outages," "delayed fault clearing," "Interconnection Reliability Operating Limit (IROL)," and "Interconnection Reliability Operating Limit T_v (IROL T_v)."[8]

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On December 27, 2007 the Commission approved the three Reliability Standards concerning Facilities Design, Connections and Maintenance (FAC) that were developed by the NERC or ERO. In addition, the Commission has directed the ERO to develop a modification to one of the three Reliability Standards that are being approved as mandatory and enforceable. The Commission is also approving a regional difference for the Western Interconnection administered by the Western Electricity Coordinating Council (WECC) which is incorporated into FAC-010-1 and FAC-011-1. Lastly, the Commission is accepting three new terms for the NERC Glossary of Terms Used in Reliability Standards, is sending back another proposed term, and is directing the ERO to submit modifications to its proposed Violation Risk Factors consistent with the Commission's prior orders.

Note: After submitting these FAC Reliability Standards, NERC filed proposed Violation Risk Factors that correspond to each Requirement of the proposed Reliability Standards.[9] According to NERC, Violation Risk Factors measure the relative risk to the Bulk-Power System associated with the violation of Requirements within the Reliability Standards.

A. Justification

8 In Order No. 693, at P 1893-98, the Commission approved the NERC glossary and directed specific modifications to the document.

9 See NERC, Request for Approval of Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-10-000, Exh. A (March 23, 2007); and NERC, Request for Approval of Supplemental Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-12-000, Exh. A (May 4, 2007). In its orders addressing the violation risk factors, the Commission addressed only those Violation Risk Factors pertaining to the 83 Reliability Standards approved in Order No. 693. North American Electric Reliability Corp., 119 FERC ¶ 61,145, at P 14 (2007) (Violation Risk Factor Order) and North American Electric Reliability Corp., 119 FERC ¶ 61,321, at P 4 (2007) (Supplemental VRF Order).

1. CIRCUMSTANCES THAT MAKE THE COLLECTION OF INFORMATION NECESSARY

EPAct 2005 added a new section 215 to the FPA, which provides for a system of mandatory and enforceable Reliability Standards. Section 215(d)(1) of the FPA provides that the ERO must file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective, i.e., mandatory and enforceable, with the Commission. On April 4, 2006, and as later modified and supplemented, the ERO submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA.

Section 215(d)(2) of the FPA provides that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a proposed Reliability Standard if it meets the statutory standard for approval, giving due weight to the technical expertise of the ERO. Alternatively, the Commission may remand a Reliability Standard pursuant to section 215(d)(4) of the FPA. Further, the Commission may order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to "carry out" section 215 of the FPA.[10] The Commission's action in this Proposed Rule is based on its authority pursuant to section 215 of the FPA.

A reliability standard defines obligations or requirements of utilities and other entities that operate, plan and use the bulk power system in North America. Meeting these requirements helps ensure the reliable planning and operation of the bulk power system. Each NERC Reliability Standard details the purpose of the standard, the entities that must comply, the specific actions that constitute compliance, and how the standard will be measured.

Standards address aspects of the operation and planning of the bulk power system such as: real-time transmission operations, balancing load and generation, emergency operations, system restoration and blackstart, voltage control, cyber security, vegetation management, facility ratings, disturbance reporting, connecting facilities to the grid, certifying system operators, and personnel training. Standards detail how the system should perform, but not how the system should be designed. Individual owners, operators and users of the bulk power system determine if the system should be expanded or changed, and how, in order to achieve the standards.

Recent Events

A common cause of the past major regional blackouts was violation of NERC's then Operating Policies and Planning Standards. During July and August 1996, the west coast of the United States experienced two cascading blackouts caused by violations of voluntary Operating Policies.[11] In response to the outages, the Secretary of Energy convened a task force to advise

10 See 16 U.S.C. 824o(d)(5) (2006).

11 The Electric Power Outages in the Western United States, July 2-3, 1996, at 76

the Department of Energy (DOE) on issues needed to be addressed to maintain the reliability of the bulk-power system. In a September 1998 report, the task force recommended, among other things, that federal legislation should grant more explicit authority for FERC to approve and oversee an organization having responsibility for bulk-power reliability standards.[12] Further, the task force recommended that such legislation provide for Commission jurisdiction for reliability of the bulk-power system and FERC implementation of mandatory, enforceable reliability standards.

Electric reliability legislation was first proposed after issuance of the September 1998 task force report and was a common feature of comprehensive electricity bills since that time. A stand-alone electric reliability bill was passed by the Senate unanimously in 2000. In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable as part of the National Energy Policy.[13]

Under the new electric power reliability system enacted by the Congress, the United States will no longer rely on voluntary compliance by participants in the electric industry with industry reliability requirements for operating and planning the Bulk-Power System. Congress directed the development of mandatory, Commission-approved, enforceable electricity Reliability Standards. The Commission believes that, to achieve this goal, it is necessary to have a strong ERO that promotes excellence in the development and enforcement of Reliability Standards.

A mandatory Reliability Standard should not reflect the "lowest common denominator" in order to achieve a consensus among participants in the ERO's Reliability Standard development process. Therefore, the Commission will carefully review each Reliability Standard submitted and, where appropriate, later remand if necessary, an inadequate Reliability Standard to ensure that it protects reliability, has no undue adverse effect on competition, and can be enforced in a clear and even-handed manner.

NERC stated that the three new Reliability Standards ensure that system operating limits and interconnection reliability operating limits are developed using consistent methods and that those methods contain certain essential elements.[14] NERC requested an effective date of July 1, 2007 for Reliability Standards FAC-010-1, October 1, 2007 for FAC-011-1, and January 1, 2008 for FAC-014-1 (since revised see "Effective Date" below). NERC explained that it has

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(ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/doerept.pdf) and WSCC Disturbance Report, For the Power System outage that Occurred on the Western Interconnection August 10, 1996, at 4 (ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/AUG10FIN.pdf).

12 Maintaining Reliability in a Competitive U.S. Electricity Industry, Final report of the Task Force on Electric System Reliability, Secretary of Energy Advisory Board, U.S. Department of Energy (September 1998), at 25-27, 65-67.

13 Report of the National Energy Policy Development Group, May 2001, at p. 7-6.

14 NERC filing at 20. Section 39.5(a) of the Commission's regulations, 18 CFR 39.5 (2007), provides that the ERO's submission of a new or modified Reliability Standard must include, inter alia, a concise statement of the basis and purpose of the proposed Reliability Standard and a demonstration that the proposal is just, reasonable not unduly discriminatory or preferential, and in the public interest. The Commission notes that NERC's filing, at 20, includes a single paragraph describing the purpose of the proposed Reliability Standards. Future Reliability Standard filings may be subject to a deficiency letter if they fail to satisfy the filing requirements set forth in the Commission's regulations.

proposed a phased schedule for implementing these Reliability Standards so that each responsible entity has sufficient time to develop the methodology for determining stability limits associated with a list of multiple contingencies, to update the system operating limits as needed to comply with the new requirements, to communicate the limits to others, and to prepare the documentation necessary to demonstrate compliance. (See item no. 12 for drafts of the proposed standards).

2. HOW, BY WHOM, AND FOR WHAT PURPOSE THE INFORMATION IS TO BE USED AND THE CONSEQUENCES OF NOT COLLECTING THE INFORMATION

Prior to enactment of section 215, FERC had acted primarily as an economic regulator of wholesale power markets and the interstate transmission grid. In this regard, the Commission acted to promote a more reliable electric system by promoting regional coordination and planning of the interstate grid through regional independent system operators (ISOs) and regional transmission organizations (RTOs), adopting transmission pricing policies that provide price signals for the most reliable and efficient operation and expansion of the grid, and providing pricing incentives at the wholesale level for investment in grid improvements and assuring recovery of costs in wholesale transmission rates.

As part of FERC's efforts to promote grid reliability, the Commission created a new Division of Reliability within the Office of Markets, Tariffs and Rates. This office has subsequently become an independent office, the Office of Electric Reliability. One task of this office has been to participate in North American Reliability Council's (NERC's) Reliability readiness reviews of balancing authorities, transmission operators and reliability coordinators in North America to determine their readiness to maintain safe and reliable operations. FERC also directed transmission owners to report by June 2004, on the vegetation management practices they use for transmission and rights of way.[15] FERC's Office of Electric Reliability has also engaged in studies and other activities to assess the longer-term and strategic needs and issues related to power grid reliability.

Sufficient supplies of energy and a reliable way to transport those supplies to customers are necessary to assure reliable energy availability and to enable competitive markets. Reasonable supply relative to demand is essential for competitive markets to work. Without sufficient delivery infrastructure, some suppliers will not be able to enter the market, customer choices will be limited, and prices will be needlessly volatile. The Commission assists in creating a more reliable electric system by:

- Fostering regional coordination and planning of the interstate grid through independent system operators and regional transmission organizations;

15 1902-0207, FERC-723 "Vegetation Report" in Docket No. EL04-52-000. El04-52-000. This was a one-time information collection that expired 10/31/04. FERC submitted a report to Congress in September 2004 that set forth the Commission's findings and recommendations, including the need for mandatory, enforceable reliability rules.

- Adopting transmission policies that provide price signals for the most reliable and efficient operation and expansion of the grid; and
- Providing pricing incentives at the wholesale level for investment in grid improvements and ensuring opportunities for cost recovery in wholesale transmission rates.

The passage of the Electricity Modernization Act of 2005 added to the Commission's efforts identified above, by giving it the authority to strengthen the reliability of the interstate grid through the grant of new authority pursuant to section 215 of the FPA which provides for a system of mandatory Reliability Standards developed by the ERO, established by FERC, and enforced by the ERO and Regional Entities.

The three new Reliability Standards will establish requirements to assure that transmission operators across the country will use consistent methodologies to determine operating limits of the Bulk Power System for planning and operations purposes. The standards also acknowledge regional differences in Western Electric Coordinating Council (WECC) that are intended to provide higher levels of reliability than the proposed national Reliability Standards.

These three standards set requirements for the development of system operating limits (SOLs) of the Bulk-Power System for use in the planning and operation horizons. In addition, these standards ensure that the SOLs are determined based on established methodology. SOLs are based on certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre-and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre-and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Additionally, NERC has proposed the addition and/or revision of the following terms to its Glossary of Terms Used in Reliability Standards (NERC glossary): "cascading outages," "delayed fault clearing," "Interconnection Reliability Operating Limit (IROL)," and "Interconnection Reliability Operating Limit T_v (IROL T_v)."[16]

<u>FAC-010-1 (System Operating Limits Methodology for the Planning Horizon)</u>

The stated Purpose of the Reliability Standard is 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."[17] FAC-010-1 applies to "planning authorities"

16 In Order No. 693, at P 1893-98, the Commission approved the NERC glossary and directed specific modifications to the document.

17 The NERC glossary defines system operating limit or SOL as "the value . . . that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. . . ."

and requires each planning authority to document its methods for determining system operating limits and to share the calculated limits with reliability entities.[18]

> Requirement R1 of the Reliability Standard provides that the Planning Authority shall have a documented SOL methodology within its planning area that is applicable to the planning time horizon, does not exceed facility ratings, and includes a description of how to identify the subset of SOLs that qualify as interconnection reliability operating limits (IROLs).[19]
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> Requirement R2 of the Reliability Standard identifies specific considerations that must be included in the methodology. For example, Requirement R2.1 provides that the methodology must include a requirement that SOLs provide bulk electric system performance so that, in the pre-contingency state and with all facilities in service, the bulk electric system shall demonstrate transient, dynamic and voltage stability and all facilities shall be within their facility ratings.

Reliability Standard FAC-010-1 identifies data retention requirements and two sets of Levels of Non-Compliance, one of general applicability and one for the Western Interconnection. FAC-010-1 also includes Measures corresponding to each Requirement. It identifies the regional reliability organization as the entity responsible for compliance monitoring.

<u>FAC-011-1 (System Operating Limits Methodology for the Operations Horizon)</u>

Proposed Reliability Standard FAC-011-1 requires each reliability coordinator to develop a SOL methodology for determining which of the stability limits associated with the list of multiple contingencies are applicable for use in the operating horizon based on actual or expected system conditions.

> Requirement R2 of FAC-011-1 identifies specific considerations that must be included in the methodology in a pre-contingency state and following one or multiple contingencies.

<u>FAC-014-1 (Establish and Communicate System Operating Limits)</u>

Reliability Standard FAC-014-1 requires each reliability coordinator, planning authority, transmission planner and transmission operator to develop and communicate SOL limits in

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18 The NERC glossary defines “planning authority” as “the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.” The Commission notes that Version 2 of NERC’s Reliability Functional Model, adopted by the NERC Board of Trustees on February 10, 2004, at 14-16, discusses the role of the planning authority. However, Version 3 of NERC’s Reliability Functional Model, adopted by the NERC Board of Trustees on February 13, 2007, at 13-15, appears to have replaced “planning authority” with the new term “planning coordinator.”

19 NERC has proposed the following definition of IROL, “a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.”

accordance with the methodologies developed pursuant to FAC-010-1 and FAC-011-1. FAC-014-1 requires the reliability coordinator to ensure that SOLs are established for its "reliability coordinator area" and that the SOLs are consistent with its SOL methodology. It provides that each transmission operator, planning authority and transmission planner must establish SOLs as directed by its reliability coordinator that are consistent with the reliability coordinator's methodology. Further, FAC-014-1 requires the reliability coordinator, planning authority and transmission planner to provide its SOLs to those entities that have a reliability-related need.[20]

As noted in the NOPR and reiterated in the Final Rule, the three proposed Standards do not require responsible entities to file information with the Commission. In addition, with the exception of a three year self-certification of compliance, the Reliability Standards do not require responsible entities to file information with NERC or the Regional Entities. However, the Reliability Standards do require responsible entities to develop and maintain certain information for a specific period of time, subject to inspection by the ERO (NERC) or Regional Entities.

These three Reliability Standards serve an important reliability purpose in ensuring that SOLs used in the reliable planning and operation of the Bulk-Power System are determined based on an established methodology. Moreover, they clearly identify the entities to which they apply and contain clear and enforceable requirements.

3. **DESCRIBE ANY CONSIDERATION OF THE USE OF IMPROVED TECHNOLOGY TO REDUCE BURDEN AND TECHNICAL OR LEGAL OBSTACLES TO REDUCING BURDEN.**

The Commission has developed the capability for electronic filing of all major submissions to the Commission. In Order No. 619, the Commission established an electronic filing initiative that permits over 40 qualified types of documents to be filed over the Internet to its website. This includes the ability to submit standard forms using software that is readily available and easy to use. Electronic filing, combined with electronic posting and service over the web site, permits staff and the public to obtain filings in a faster and more efficient manner. The Commission is working to expand the qualified types of documents that can be filed over the Internet.

In order that the Commission is able to perform its oversight function with regard to Reliability Standards that are proposed by the ERO and established by the Commission, it is essential that the Commission receive timely information regarding all or potential violations of Reliability Standards. While section 215 of the FPA contemplates the filing of the record of an ERO or Regional Entity enforcement action, FERC needs information regarding violations and potential violations at or near the time of occurrence. Therefore, it will work with the ERO and

20 The Notice of Proposed Rulemaking (NOPR) provides additional background on the content of each FAC Reliability Standard. Facilities, Design, Connections and Maintenance Mandatory Reliability Standards, Notice of Proposed Rulemaking, 72 FR 160 (Aug. 20, 2007), FERC Stats. And Regs. ¶ 32,622, at P 9-36 (Aug. 13, 2007).

regional reliability organizations to be able to use the electronic filing of information so the Commission receives timely information.

The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet website for public inspection. (See item no. 7 for further discussion.)

4. **DESCRIBE EFFORTS TO IDENTIFY DUPLICATION AND SHOW SPECIFICALLY WHY ANY SIMILAR INFORMATION ALREADY AVAILABLE CANNOT BE USED OR MODIFIED FOR USE FOR THE PURPOSE(S) DESCRIBED IN INSTRUCTION NO. 2**

Filing requirements are periodically reviewed as OMB review dates arise or as the Commission may deem necessary in carrying out its responsibilities under the FPA in order to eliminate duplication and ensure that filing burden is minimized. There are no similar sources of information available that can be used or modified for these reporting purposes. The filing requirements in proposed FERC-725D will incorporate NERC's requirements. However, all reliability requirements will be subject to FERC approval along with the requirements developed by Regional Entities and Regional Advisory Bodies and the ERO.

5. **METHODS USED TO MINIMIZE BURDEN IN COLLECTION OF INFORMATION INVOLVING SMALL ENTITIES**

FERC-725D is a filing requirement concerning the implementation of reliability standards by the Electric Reliability Organization and its responsibilities as well as those of Regional Entities and Regional Advisory Bodies in the development of Reliability Standards. The Electricity Modernization Act specifies that the ERO and Regional Entities are not departments, agencies or instrumentalities of the United States government and will not be like most other businesses, profit or not-for–profit. Congress created the concept of the ERO and Regional Entities as select, special purpose entities that will transition the oversight of the Bulk-

Power System reliability from voluntary, industry organizations to independent organizations subject to Commission jurisdiction.

Section 215(b) of the FPA requires all users, owners and operators of the Bulk-Power System to comply with Commission-approved Reliability Standards. Each proposed Reliability Standard submitted for approval by NERC applies to some subset of users, owners and operators. Most of the entities, i.e., planning authorities, reliability coordinators, transmission planners and transmission operators, to which the requirements of this rule would apply do not fall within the definition of small entities.[21]

Based on available information regarding NERC's compliance registry, approximately 250 entities will be responsible for compliance with the three new Reliability Standards. It is estimated that one-third of the responsible entities, about 80 entities, would be municipal and cooperative organizations. The proposed Reliability Standards would apply to planning authorities, transmission planners, transmission operators and reliability coordinators, which tend to be larger entities. Thus, the Commission believes that only a portion, approximately 30 to 40 of the municipal and cooperative organization to which the proposed Reliability Standards would apply, qualify as small entities.[22] The Commission does not consider this a substantial number. Moreover, as discussed above, the proposed Reliability Standards will not be a burden on the industry since most if not all of the applicable entities currently perform SOL calculations and the proposed Reliability Standards will simply provide a common methodology for those calculations.

6. CONSEQUENCE TO FEDERAL PROGRAM IF COLLECTION WERE CONDUCTED LESS FREQUENTLY

The Electric Reliability Organization will conduct periodic assessments of the reliability and adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, Regional Entities, and Regional Advisory Bodies annually or more frequently if so ordered by the Commission. The ERO and Regional Entities will report to FERC on their enforcement actions and associated penalties and to the Secretary of Energy, relevant Regional entities and relevant Regional Advisory Bodies annually or quarterly in a manner to be prescribed by the Commission. If the information were conducted

21 The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. See 15 U.S.C. 632 (2000). According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceding year.

22 According to the DOE's Energy Information Administration (EIA), there were 3,284 electric utility companies in the United States in 2005, and 3,029 of these electric utilities qualify as small entities under the SBA definition. Among these 3,284 electric utility companies are: (1) 883 cooperatives of which 852 are small entity cooperatives; (2) 1,862 municipal utilities, of which 1842 are small entity municipal utilities; (3) 127 political subdivisions, of which 114 are small entity political subdivisions; and (4) 219 privately owned utilities, of which 104 could be considered small entity private utilities. See Energy Information Administration Database, Form EIA-861, Dept. of Energy (2005), available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

less frequently or discontinued, the Commission would be placed at a disadvantage in not having the data necessary for monitoring its mandated obligations.

7. EXPLAIN ANY SPECIAL CIRCUMSTANCES RELATING TO THE INFORMATION COLLECTION

FERC-725D is a filing requirement necessary to comply with the applicable provisions of the Electricity Modernization Act of 2005 and section 215 of the Federal Power Act.

In accordance with section 39.5 of the Commission's regulations, the ERO must file each Reliability Standard or a modification to a Reliability Standard with the Commission. The filing is to include a concise statement of the basis and purpose of the proposed Reliability Standard, either a summary of the Reliability development proceedings conducted by the ERO or a summary of the Reliability Standard development proceedings conducted by a Regional Entity together with a summary of the Reliability Standard review proceedings of the ERO and a demonstration that the proposed Reliability Standard is "just, reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO must make each effective Reliability Standard available on its Internet website. Copies of the effective Reliability Standards will be available from the Commission's Public Reference Room.

The Commission requires an original and seven copies of the proposed Reliability Standard or to the modification to a proposed Reliability Standard to be filed. This exceeds the OMB guidelines in 5 CFR 1320.5(d) (2) (iii) because of the number of divisions within the Commission that must analyze the standard and corresponding reports in order to carry out the regulatory process. The original is docketed, imaged through e-Library and filed as a permanent record for the Commission. The remaining copies are distributed to the necessary offices of the Commission with one being placed immediately in the Commission's Public Reference Room for public use. Since the time frame for responses to the request is very limited, the multiple hard copies are necessary for the various offices to review, analyze and prepare the final order at the same time. The electronic filing initiative at FERC, may in the near future, allow for relief of the number of copies, but at this time, the program turn around time for docketing, imaging and retrieval does not permit sufficient time to review the filings and to prepare the necessary documents for the processing of these filings.

In addition, individual reliability standards may have records retention schedules that exceed OMB guidelines in 5 CFR 1320.5(d)(2)(iv) of not retaining records for no longer than three years.

8. DESCRIBE EFFORTS TO CONSULT OUTSIDE THE AGENCY: SUMMARIZE PUBLIC COMMENTS AND THE AGENCY'S RESPONSE TO THESE COMMENTS

Each Commission rulemaking (both NOPRs and Final Rules) are published in the Federal Register, thereby affording all public utilities and licensees, state commissions, Federal agencies, and other interested parties an opportunity to submit data, views, comments or suggestions concerning the proposed collection of data. The notice procedures also allow for public conferences to be held as required. The Commission has held several workshops and technical conferences to address reliability issues including transition to the NERC reliability standards, operator tools, and reactive power. Comments in response to the NOPR were due by September 21, 2007. Approximately 21 entities filed comments, including several late-filed comments.

The Commission is directing NERC to conduct the following changes:

•modify FAC-011-1, Requirement 2.3;
• send back NERC's definition of "Cascading Outages" for further clarification, and
• revise the Violation Risk Factors that are inconsistent with the Commission's Violation Risk Factor guidelines.

The Commission is approving the three FAC Reliability Standards including the WECC regional differences as contained in FAC-010-1 and FAC-011-1. The Commission also accepts NERC's proposals to add or revise the following terms in the NERC glossary: "Delayed Fault Clearing," "Interconnection Reliability Operating Limit (IROL)," and "Interconnection Reliability Operating Limit T_v (IROL T_v)."[23] Finally, the Commission accepts certain Violation Risk Factors with the exceptions as discussed below.

Standard FAC-011-1, Requirement (R) 2.3

As described in the NOPR, Requirement R2.3.2 of FAC-011-1 provides that the system's response to a single contingency may include, inter alia, "[i]nterruption 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."[24] In the NOPR, the Commission requested that NERC clarify the meaning of the phrase "if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied." In particular, the Commission questioned whether this provision treats load forecast error as a contingency and would allow an interruption due to an inaccurate weather forecast.

Comments

NERC stated that deviations between anticipated conditions and real-time conditions, such as load forecast errors, are not contingencies by definition in the NERC glossary. However, in real-time, the operators must take the actions necessary to maintain bulk electric

23 In Order No. 693 at P 1893-98, the Commission approved the NERC glossary, directing specific modifications to the document.
24 NOPR at P 25.

system reliability given current conditions. Available actions include load shedding if operating conditions warrant.

NERC stated that when the real-time operating conditions do not match the assumed studied conditions, the deviation can reach a magnitude such that the operator must take actions different from those anticipated by the study. From that perspective, the study error has the same affect on the bulk electric system as many actual contingencies. While these deviations do not meet the approved definition of a "contingency" in NERC's glossary, NERC stated that system operators need to react to these unexpected circumstances expeditiously and interruption of other network customers is allowed and expected if conditions warrant such an action. NERC maintains that this provision is necessary to ensure that system operators have the ability to shed load without penalty to preserve the integrity of the bulk electric system. Thus, while it does not classify and study forecast error as a "contingency," NERC asserts that a significant gap between actual and studied conditions (such as a large error in load forecast) can be treated as though it were a contingency under the proposed Reliability Standard.

NERC stated that all anticipatory studies must begin with a reasonable set of assumptions.[25] According to NERC, when "real time" approaches that time period that was assessed by the particular anticipatory study, real time conditions may not replicate the predicted state. For example, unscheduled transmission outages may have occurred, generation outages may have occurred, the system could be operating with one or more Transmission Loading Relief procedures or other congestion management action such as redispatch in effect requiring a different generation dispatch than anticipated when the applicable study was being conducted. Moreover, the actual load level and load diversity could be different than forecasted and used in the corresponding study, or the transmission facility loading levels could be significantly higher than studied because any of or all of the conditions above – either on the system being studied or on near-by systems.

NERC asserted that FAC-011-1, Requirement R2.3.2 allows interruption of network customers following a contingency and in anticipation of the next potential unscheduled event if the real-time operating conditions are more adverse than anticipated. The adjustment in response to an unscheduled outage or load forecast error, for example, would be to return to a reliable state, recognizing the conditions as they exist at the time — available generation, transmission configuration, available reactive resources, load level and load diversity, and conditions on other systems.

Similarly, FirstEnergy argued that no change should be made, because FAC-011-1 is intended to permit a system operator to implement the best reliability response, but does not require an inquiry into the cause of system conditions.

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25 See NERC Comments at 26. NERC states that these assumptions would include: (1) existing and scheduled transmission outages for that time period, (2) existing and scheduled generation outages for that time period, (3) projected generation dispatch for that time period, (4) predicted status of voltage control devices, and (5) load level and load diversity for the future time period being scheduled.

ISO/RTO Council viewed “load greater than studied” as providing an example of when “real-time operating conditions are more adverse then studied,” not as a qualifier of that language. ISO/RTO Council did not support treating load forecast error as a contingency. While load forecast error may be unpredicted, normally time is available for adjustments. Commenters noted that operating reserve requirements should provide sufficient margin for error, as reflected in the NERC glossary.[26]

Southern and NRECA commented that load forecast error is not a contingency, but is a failure in one element of the data that make up the day-ahead study base case. The day-ahead study is used to identify contingencies where reliability criteria may not be met (that is, SOLs are exceeded). Southern argued that the purpose of this process is to lessen the potential for problems occurring in real time. The day-ahead study is used to schedule resources and outages, and adjustments are made in real time as actual conditions differ from forecasted conditions. To respond to changing conditions, a system operator may rely on switching procedures, redispatch, curtailments and load shedding, but load shedding should be avoided.

NRECA argued that, because the matter is technical, it should be addressed by the ERO, through the Reliability Standards development process and not through a Commission rulemaking. Ameren noted that other load shedding conditions exist and suggests that the list of examples be expanded or that the specific reference to load forecast errors be removed to avoid confusion. Duke maintained that the phrase, “or if real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied,” should be deleted because the focus of Requirement R2.3.2 is that a response to a second contingency may include interruption of non-consequential load, while extreme weather, while a possibility, is unrelated to SOL methodology or contingencies.

Commission Response

The Commission agrees with Southern, NRECA and ISO/RTO Council that load forecast error is not a contingency and should not be treated as such for the purposes of complying with mandatory Reliability Standards. NERC has failed to support its assertion that a significant gap between actual and studied conditions (such as a large error in load forecast) can be treated as though it were a contingency under the proposed Reliability Standard. While such a situation may cause unanticipated contingencies to become critical, correcting for load forecast error is not accomplished by treating the error as a contingency, but is addressed under other Reliability Standards. For instance, transmission operators are required to modify their plans whenever they receive information or forecasts that are different from what they used in their present plans. Furthermore, variations in weather forecasts that result in load forecast errors are more properly addressed through operating reserve requirements.[27] Once the operating reserve is

26 See, e.g., ISO/RTO Council and NRECA Comments.
27 See, e.g., NERC, Request for Approval of Reliability Standards, Glossary of Terms Used in Reliability Standards, at 12 (April 4, 2006) (April 2006 Reliability Standards Filing) (defining Operating Reserve as “That capability above firm system demand required to provide for regulation, load forecast errors, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserves” (emphasis added)).

activated, BAL-002-0 requires correction through system adjustments to alleviate reliance on operating reserves within 90 minutes rather than treating the incorrect forecast as a contingency.[28] NERC's interpretation could be used to justify not taking timely emergency action prior to load shedding, or to influence how other Reliability Standards are interpreted, which could result in moving to "lowest common denominator" Reliability Standards.

The Commission does not find that NERC's interpretation is required by the text of FAC-011-1, Requirement R2.3.2. When read in connection with Requirement R2.3, it is clear that the operating conditions "more adverse than anticipated," referred to in sub-Requirement R2.3.2 are exacerbating circumstances that are distinct from the actual contingency to be addressed that is referred to in Requirement R2.3. It is the existence of the exacerbating circumstance in combination with a separate and distinct contingency that triggers the potential for an interruption of network customers in R2.3.2. However, that reading does not support treating "load greater than studied" as a contingency.

The Commission disagrees with NERC's reading of sub-Requirement R2.3.2 and interpretation of the phrase "load greater than studied." However, the Commission finds that the meaning of Requirement R.2.3 and sub-Requirement R.2.3.2 is not otherwise unclear. Therefore, keeping with the Commission's approach in the Final Rule, it will approve FAC-011-1, but is directing NERC to revise the Reliability Standard through the Reliability Standards development process to address the Commission's concern. This could, for example, be accomplished by deleting the phrase, "e.g., load greater than studied" from sub-Requirement R.2.3.2.

Cascading Outages

Although the NERC glossary does not currently include a definition of Cascading Outage, it includes the following approved definition of Cascading:

> Cascading: 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.[29]

NERC proposes the following new definition of Cascading Outages:

> 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

28 See Reliability Standard BAL-002-0, sub-Requirements R4.2 and R6.2. See also EOP-002-1 (requiring Energy Emergency Alert 1 to be declared if a balancing authority, reserve sharing group or load serving entity is concerned about sustaining its required Operating Reserves).
29 April 2006 Reliability Standards Filing, Glossary at 2.

cannot be restrained from spreading beyond a pre-determined area.

The NOPR stated that the extent of an outage that would be considered a cascade is ambiguous in the current term Cascading. The Commission noted that the new definition of Cascading Outages includes a similar phrase "a pre-determined area," which may lead to different interpretations of the extent of an outage that would be considered a Cascading Outage. In the NOPR, the Commission stated that it understands that this phrase could be interpreted to refer to a scope as small as the elements that would be removed from service by local protective relays to as large as the entire balancing authority. The Commission objected to the possibility that the Cascading Outages definition might consider the loss of an entire balancing authority as a non-cascading event. The NOPR sought comment on the Commission's proposal to accept the glossary definition but clarify the scope of an acceptable "pre-determined area." Such an area would not extend beyond "the loss of facilities in the bulk electric systems that are beyond those that would be removed from service by primary or backup protective relaying associated with the initiating event."

Comments

NERC, EEI and APPA, Ameren, Duke, PG&E, Southern and Xcel disagreed with the Commission's interpretation of the term Cascading Outages. While FirstEnergy, Southern and MidAmerican agree that NERC's proposed definition of Cascading Outages may be open to interpretation, they also objected to the Commission's interpretation of the term. Several commenters, including Duke, NRECA and Ameren, asserted that the Commission's proposal is overly prescriptive.

According to NERC, as well as EEI and APPA, the term was designed to provide a classification for an event, not to identify attributes of an event such as scope, risk or acceptable impact. As EEI and APPA understand the term, Cascading Outages will be used to describe facts and circumstances in the analysis of widespread uncontrolled outages that take place when there are unexpected equipment failures or strong electrical disturbances. The analyses of these highly unusual and large-scale events, however, will take place through processes described in the NERC Rules of Procedure. EEI and APPA maintain that the key to NERC's proposed definition of Cascading Outages is "uncontrolled" and that the scope of the outage is unknown.

NERC agreed with the Commission's concern that the definition of Cascading Outages was not intended to allow for the loss of an entire balancing authority unless such an area conforms to the area predetermined by studies. However, commenters maintain that there are additional safety nets that are intended to confine an outage to a pre-set area of the bulk electric system, including special protection systems, protective relays, remedial action schemes, and underfrequency and undervoltage load shedding applications. According to commenters, the Commission's proposed interpretation appears to ignore the role of transmission operators in managing and containing outage situations and the use of these systems.[30]

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30 <u>See</u>, <u>e.g</u>., NERC, EEI and APPA, and Duke Comments.

ISO/RTO Council notes that system planning studies examining the extent of outages anticipate the operation of protective relay options providing primary protection, with backup protective relays provided by "secondary protection, zone 2 protection and special protection systems." ISO/RTO Council requests a clarification as to what backup protective relaying means and whether or not planned operation of a special protection system to contain impacts of outages is regarded as backup protection.

Several commenters maintained that the Commission's proposed interpretation of the term Cascading Outages is too broad. NERC, Ameren, PG&E, Southern, and EEI and APPA asserted that this interpretation would result in too many outages being defined as Cascading Outages under the Commission's interpretation. They maintain that even an outage that is contained exactly as planned could be designated as a Cascading Outage. Further, NERC states that the implication of applying the Commission's definition to the TPL evaluations required in Table 1 would be extraordinary in scope and impact and the cost would be prohibitive. Additionally, NERC and Southern stated that the Commission's interpretation is in conflict with Table 1 in the TPL-001-0 through TPL-004-0 Reliability Standards that the Commission approved in Order No. 693.

NERC, therefore, recommended that the Commission reconsider its proposal to accept and interpret the term Cascading Outages. According to NERC, adoption of the Commission's proposed understanding would require a review of all NERC Reliability Standards that rely on the Cascading Outages definition to be certain that the intent of the Reliability Standards does not also change. If the definition of Cascading Outages needs to be changed, several commenters, including NERC, FirstEnergy and Southern, maintain that changes should be made through NERC's stakeholder process. Some commenters offer alternative definitions or clarifications for Cascading Outages.[31]

Ameren disagreed that the proposed phrase "beyond a pre-determined area" would invite system users to expand or contract their understanding of such an area without limit. Ameren argued that the concern that the pre-defined area be defined as too small is unfounded because the existing definition already requires that the outage not be local in nature, that is, result in outages beyond the site of the initial failure. Furthermore, the definition cannot be defined too large, since the scope for operation and planning authorities is already established.

Similarly, PG&E and Southern argued that the Commission's proposal is not necessary, because the Reliability Standards address outages in relation to the severity of their impact on the grid. PG&E maintains that the Reliability Standards limit application of the definition to an entire balancing authority, because the Reliability Standards require a technical analysis of the appropriate boundary, and distribution of the methodology used to define a "predetermined area." Therefore, according to PG&E, such a "predetermined area" could only be defined to mean the loss of an entire balancing authority when technically appropriate.

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31 See Duke, ISO/RTO Council and MidAmerican Comments.

MidAmerican requested that the Commission direct NERC to re-focus planning Reliability Standards away from the ambiguous definition of cascade and develop a definition based on maximum loss of load allowed for a given contingency, such as 1,000 MW. MidAmerican supports its 1,000 MW threshold as being a significant loss, while not exceeding the load for most balancing authorities.

Southern argued that as written, the phrase "that adversely impact the reliability of the bulk electric system" modifies Cascading Outages and not a violated system operating limit. Southern proposed that the phrase should be left in because it codifies an appropriate distinction between Cascading Outages that affect reliability and other localized events that create a controlled separation that do not impact the reliability of the system.

Xcel is concerned that the Commission's comments indicate an intent to restrict the use of controlled outages to prevent the escalation of system contingencies. Xcel states that the Commission's proposed definition represents a departure from historical interpretation and application of the term and could have significant unintended consequences.

Commission Response

The Commission will not adopt the proposed interpretation of Cascading Outages contained in the NOPR. Rather, for the reasons discussed below, the Commission sends back the term Cascading Outages. If it chooses, NERC may refile a revised definition that addresses the Commission's concerns.

The present definition of Cascading provides that "[c]ascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." In contrast, the proposed definition of Cascading Outages describes an interruption "that cannot be restrained from spreading beyond a pre-determined area." Although the language is somewhat similar, it removes the qualifying language "by studies." NERC provides no explanation for this change. The Commission is concerned that the removal of this phrase in the definition of Cascading Outage would allow an entity to identify a "predetermined area" based on considerations other than engineering criteria. For example, under the proposed definition of Cascading Outages, an entity could predetermine that an outage could spread to the edge of its footprint without considering the event to be a Cascading Outage. The Commission is concerned that the limits placed on outages should be determined by sound engineering practices.

Adding to the ambiguity, NERC has provided definitions of Cascading and Cascading Outages that seem to describe the same concept – uncontrolled successive loss of elements or facilities – but did not explain any distinction between the two terms. Nor did NERC explain why the new term is necessary and requires a separate definition. Because NERC did not describe either the need for two definitions that seem to address the same matter or the variations between the two, the Commission remands NERC's proposed definition of Cascading Outages.

If NERC decides to propose a new definition of Cascading Outages, the Commission would expect any proposed definition to be defined in terms of an area determined by engineering studies, consistent with the definition of Cascading. In addition, the Commission is concerned with the consistent, objective development of criteria with which the “pre-determined area” would be determined. Therefore, the Commission suggests that NERC develop criteria, to be found in a new Reliability Standard or guidance document, that would be used to define the extent of an outage, beyond which would be considered a Cascading Outage.

Further, the terms Cascading and Cascading Outages contain other nuanced differences. For example, the “loss of system elements” is changed to “loss of Bulk Electric System facilities” and “triggered by an incident” is changed to “triggered by an incident (or condition).” The implications of these changes are not clear to the Commission. Accordingly, if NERC submits a revised definition of Cascading Outage, it should explain the purpose and meaning of changes from the term Cascading.

Given the concerns raised by commenters that the extent of an outage may vary, the Commission will not grant at this time MidAmerican’s request to direct NERC to re-focus planning Reliability Standards away from the definition of cascade. Further, MidAmerican requests that the Commission consider new issues not raised in the NOPR. MidAmerican should raise these issues in the NERC Reliability Standards development process.

In response to ISO/RTO Council’s request, the Commission is clarifying that by “backup protective relaying,” the NOPR intended the compliance guidance to be consistent with Table 1 of the TPL Reliability Standards. Table 1 identifies the categories, contingencies, and system limits or impacts for normal and emergency conditions on the bulk electric system. A common requirement for each of the category A, B and C contingencies found in Table 1 is that after all of the system, demand and transfer impacts have been accommodated for specific contingencies, there will not be cascading outages of the bulk electric system. Since all of the planned and controlled aspects have been accommodated in this table, anything beyond these planned and controlled aspects should be a cascading outage.

Violation Risk Factors

Violation Risk Factors delineate the relative risk to the Bulk-Power System associated with the violation of each Requirement and are used by NERC and the Regional Entities to determine financial penalties for violating a Reliability Standard. NERC assigns a lower, medium or high Violation Risk Factor for each mandatory Reliability Standard Requirement.[32] The Commission also established guidelines for evaluating the validity of each Violation Risk Factor assignment.[33]

32 The specific definitions of high, medium and lower are provided in North American Electric Reliability Corp., 119 FERC ¶ 61,145, at P 9 (Violation Risk Factor Order), order on reh’g, 120 FERC ¶ 61,145 (2007) (Violation Risk Factor Rehearing).

33 The guidelines are: (1) Consistency with the conclusions of the Blackout Report; (2) Consistency within a Reliability

In separate filings, NERC identified Violation Risk Factors for each Requirement of proposed Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1.[34] NERC's filings requested that the Commission approve the Violation Risk Factors when it takes action on the associated Reliability Standards.

The NOPR proposed to approve most of the Violation Risk Factors for Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1. However, as discussed below, several of the Violation Risk Factors submitted for Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1 raise concerns.

Comments

Commenters generally oppose the Commission's proposal for raising the Violation Risk Factors. Further, they generally ask that changes to the Violation Risk Factors be made through the Reliability Standards development process.

Progress Energy maintained that violations associated with planning Reliability Standards cannot be high risk because such violations do not pose an imminent danger to the Bulk-Power System. Progress Energy contends that planning Reliability Standards are implemented over a long-term planning horizon. Progress Energy stated that entities continually update load and other forecasts and assumptions relied on to determine future transmission and distribution system needs. As these assumptions change, so do the transmission plans. Progress Energy stated that utilities provide constant oversight, frequent reviews, audits and evaluations of the planning process over the entire multi-year planning horizon. According to Progress Energy, with this type of control and oversight, it is highly unlikely that an inaccurate forecast or misassumption early in the planning horizon could result in an operational reliability concern. Consequently, planning authorities and reliability coordinators have adequate time to analyze, determine and correct planning violations before they could have an operational impact.

Progress Energy also stated that unnecessarily increasing Violation Risk Factors for planning Reliability Standards may have unintended consequences. According to Progress Energy, assigning overly conservative Violation Risk Factors will cause planning and reliability coordinators to focus more time and resources on satisfying those Reliability Standards, potentially to the detriment of other Reliability Standards. It maintained that the level of the Violation Risk Factor is intended to communicate the importance of the Reliability Standards and, consequently, the resources that should be devoted to its implementation and the magnitude

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Standard; (3) Consistency among Reliability Standards; (4) Consistency with NERC's Definition of the Violation Risk Factor Level; and (5) Treatment of Requirements that Co-mingle More Than One Obligation. The Commission also explained that this list was not necessarily all-inclusive and that it retained the flexibility to consider additional guidelines in the future. A detailed explanation is provided in Violation Risk Factor Rehearing, 120 FERC ¶ 61,145, at P 8-13.

34 See NERC, Request for Approval of Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-10-000, Exh. A (March 23, 2007), as supplemented May 4, 2007. To date, the Commission has addressed only those Violation Risk Factors pertaining to the 83 Reliability Standards approved in Order No. 693. Violation Risk Factor Order, 119 FERC ¶ 61,145.

of the penalty associated with its violation. Further, to avoid potentially costly penalties associated with violation of higher risk factors, Progress Energy maintained that planning and reliability coordinators may take a more conservative approach with their assumptions, which could quite literally result in lower TTC and ATC determinations than would otherwise be available.

Commission Response

NERC submitted 72 Violation Risk Factors corresponding to the Requirements and sub-requirements in the three FAC Reliability Standards. The Commission, giving due weight to the technical expertise of NERC as the ERO, concludes that the vast majority of NERC's designations accurately assess the reliability risk associated with the corresponding Requirements and are consistent with the guidelines set forth in the Commission's prior orders addressing Violation Risk Factors. Therefore, the Commission is approving 63 of these Violation Risk Factor designations. However, the Commission concludes that nine filed Violation Risk Factors for FAC Reliability Standards Requirements are not consistent with these guidelines and also concludes that one Requirement where no Violation Risk Factor was filed should have been assigned a Violation Risk Factor consistent with an identically worded Requirement from another FAC Reliability Standard. Thus, the Commission directs NERC to modify these ten Violation Risk Factors.[35]

NERC and other commenters, such as APPA and EEI, asked the Commission to defer to NERC on the determination of Violation Risk Factors and, instead, allow NERC to reconsider the designations using the Reliability Standards development process. The Commission has previously determined that Violation Risk Factors are not a part of the Reliability Standards.[36] In developing its Violation Risk Factor filing, NERC has had an opportunity to fully vet the FAC Violation Risk Factors through the Reliability Standards development process. The Commission believes that, for those Violation Risk Factors that do not comport with the Commission's previously-articulated guidelines for analyzing Violation Risk Factor designations, there is little benefit in once again allowing the Reliability Standards development process to reconsider a designation based on the Commission's concerns. Therefore, the Commission will not allow NERC to reconsider the Violation Risk Factor designations in this instance but, rather, direct that NERC makes specific modifications to its designations. NERC must submit a compliance filing with the revised Violation Risk Factors no later than 90 days before the effective date of the relevant Reliability Standard.

However, NERC may choose the procedural vehicle to change the ten Violation Risk Factors consistent with the Commission's directives. NERC may use the Reliability Standards

35 The ten Violation Risk Factors to which the Commission directs modification include Requirement R3.4 for FAC-011-1, where NERC did not assign a Violation Risk Factor. In this instance, the Commission assigns a Violation Risk Factor to the subject Requirement that is consistent with the Violation Risk Factor assigned to an identical Requirement for another Reliability Standard, FAC-010-1, Requirement R2.3.

36 Violation Risk Factor Rehearing, 120 FERC ¶ 61,145, at P 11-16, citing North American Reliability Corp., 118 FERC ¶ 61,030, at P 91, order on clarification and reh'g, 119 FERC ¶ 61,046 (2007).

development process, so long as it meets Commission-imposed deadlines.[37] In this instance, the Commission sees no vital reason to direct NERC to use section 1403 of its Rules of Procedure to revise the Violation Risk Factors below, so long as the revised Violation Risk Factors address the Commission's concerns and are filed no less than 90 days before the effective date of the relevant Reliability Standard. The Commission also notes that NERC should file Violation Severity Levels before the FAC Reliability Standards become effective.

In revising the Violation Risk Factors, NERC must address the Commission's concerns, and also follow the five guidelines for evaluating the validity of each Violation Risk Factor assignment. Consistent with the Violation Risk Factor Order, the Commission is directing NERC to submit a complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard and include the correct corresponding version number for each Requirement when it files revised Violation Risk Factors for the FAC Reliability Standards.

Progress Energy incorrectly claims that a planning Reliability Standard will never qualify for a high Violation Risk Factor. According to NERC, a high risk requirement includes:

> (b) . . . a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition [emphasis added].

A Violation Risk Factor assigned to Requirements of planning-related Reliability Standards represent, in a planning time frame, the potential reliability risk, under emergency, abnormal, or restorative conditions anticipated by the preparations to the Bulk-Power System. As such, how much time a planning authority or reliability coordinator has to identify and correct a violation of a planning-related Requirement is irrelevant in the assignment of an appropriate Violation Risk Factor.

The Commission also disagrees with Progress Energy that overly conservative Violation Risk Factor assignments may result in the lowering of Transmission Transfer Capability (TTC)[38] and Available Transfer Capability (ATC) determinations because planning and reliability coordinators may take a more conservative approach with assumptions to avoid potentially costly penalties. Progress Energy did not assert any specific deficiency regarding the relationship between planning Reliability Standards and TTC and ATC determinations. Because

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37See North American Electric Reliability Corp., 118 FERC ¶ 61,030, at P 91, order on compliance, 119 FERC ¶ 61,046, at P 33 (2007).

38 Available Transfer Capability (ATC) – a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses. ATC is defined as Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Violation Risk Factors do not determine the actions a responsible entity must take, but merely measure the risk of violating a Requirement to the reliability of the Bulk-Power System, it is the specific Requirements in a given Reliability Standard that establish the relationship between planning Reliability Standards and TTC and ATC determinations, not the assignment of a Violation Risk Factor. If Progress Energy has specific concerns that a Reliability Standard is having an unduly detrimental effect on TTC or ATC determinations, the Commission believes that it should raise such issues in the Reliability Standards development process.

Effective Date

In the NOPR, the Commission proposed to approve FAC-010-1, FAC-011-1 and FAC-014-1 as mandatory and enforceable Reliability Standards, consistent with NERC's original implementation plan beginning July 1, 2007 for Reliability Standard FAC-010-1; October 1, 2007 for FAC-011-1 and January 1, 2008 for FAC-014-1.

Comments

In its September 2007 comments, NERC requested that the Commission adopt updated effective dates of July 1, 2008 for FAC-010-1, October 1, 2008 for FAC-011-1 and January 1, 2009 for FAC-014-1. NERC explained that the proposed phased implementation schedule will provide each responsible entity sufficient time to determine stability limits associated with multiple contingencies, to update the system operating limits to comply with the new requirements, to communicate the limits to others, and to prepare the documentation necessary to demonstrate compliance.

No commenter objected to NERC's proposal to use staggered effective dates to implement the three Reliability Standards. However, Ontario IESO noted that FAC-010-1 and FAC-011-1 became effective in Ontario, Canada on October 1, 2007, making implementation of the Reliability Standards in Ontario and the United States inconsistent so long as the Commission delays approval or remands the Reliability Standards.

Commission Response

The Commission agrees that it is appropriate in this instance to adopt NERC's revised effective dates of July 1, 2008 for FAC-010-1, October 1, 2008 for FAC-011-1 and January 1, 2009 for FAC-014-1. Given that this Final Rule will not be effective until January 2008, it is reasonable to allow responsible entities in the United States adequate time to comply with these Reliability Standards.

As for Ontario IESO's concerns with the different implementation dates in Ontario and the United States, the Commission agrees that effective dates should be coordinated if practicable. In these circumstances, however, the Commission foresees no problems arising from the effective dates approved in the Final Rule.

9. **EXPLAIN ANY PAYMENT OR GIFTS TO RESPONDENTS**

No payments or gifts have been made to respondents.

10. **DESCRIBE ANY ASSURANCE OF CONFIDENTIALITY PROVIDED TO RESPONDENTS**

The Commission generally does not consider the data filed to be confidential. However, certain standards may have confidentiality provisions in the standard.

The Commission has in place procedures to prevent the disclosure of sensitive information, such as the use of protective orders and rules establishing critical energy infrastructure information (CEII). However, the Commission believes that the specific, limited area of Cyber security Incidents requires additional protections because it is possible that system security and reliability would be further jeopardized by the public dissemination of information involving incidents that compromised the cyber security system of a specific user, owner or operator of the Bulk-Power System. In addition, additional information provided with a filing may be submitted with a specific request for confidential treatment to the extent permitted by law and considered pursuant to 18 C.F.R. 388.112 of FERC's regulations.

11. **PROVIDE ADDITIONAL JUSTIFICATION FOR ANY QUESTIONS OF A SENSITIVE NATURE THAT ARE CONSIDERED PRIVATE.**

There are no questions of a sensitive nature that are considered private.

12. **ESTIMATED BURDEN OF COLLECTION OF INFORMATION**

The three proposed Reliability Standards do not require responsible entities to file information with the Commission. Nor, with the exception of a three year self-certification of compliance, do the Reliability Standards require responsible entities to file information with the ERO or Regional Entities. However, the Reliability Standards do require responsible entities to develop and maintain certain information for a specified period of time, subject to inspection by the ERO or Regional Entities.

> Reliability Standard FAC-010-1 requires the planning authority to have a documented methodology for use in developing system operating limits or SOLs and must retain evidence that it issued its SOL methodology to relevant reliability coordinators, transmission operators and adjacent planning authorities. Likewise, the planning authority must respond to technical comments on the methodology within 45 days of receipt. Further, each planning authority must self-certify its compliance to the compliance monitor once every three years.

Reliability Standard FAC-011-1 requires similar documentation by the reliability coordinator.

Reliability Standard FAC-014-1 requires the reliability coordinator, planning authority, transmission operator, and transmission planner to verify compliance through self-certification submitted to the compliance monitor annually. These entities must also document that they have developed SOLs consistent with the applicable SOL methodology and that they have provided SOLs to entities identified in Requirement 5 of the Reliability Standard. Further, the planning authority must maintain a list of multiple contingencies and their associated stability limits.

The three draft standards as proposed by NERC are identified below with highlighted text identifying data requirements.

FAC Standards

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

2. Number: FAC-010-1

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.

R2.3.3. 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:

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 noncompliance.

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 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.

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.

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

3. Levels of Non-Compliance for Western Interconnection:

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.

1. Title: System Operating Limits Methodology for the Operations Horizon
2. Number: FAC-011-1
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 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, 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:
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 noncompliance.

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 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.

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.

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

3. Levels of Non-Compliance for Western Interconnection:

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

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, and 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.

1. Title: Establish and Communicate System Operating Limits

2. Number: FAC-014-1

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.
R5.1.3. 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.

Regional Differences

None identified.

Definitions:

Facility	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
System Operating Limit	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

The Commission's estimates below regarding the number of respondents is based on the NERC compliance registry as of April 2007. NERC and the Regional Entities have identified approximately 170 Investor Owned Utilities, and 80 Large Municipals and Cooperatives. NERC's compliance registry indicates that there is a significant amount of overlap among the entities that perform these functions. In some instances, a single entity may be registered under all four of these functions. Thus, the Commission estimates that the total number of entities required to comply with the information "reporting" or development requirements of the proposed Reliability Standards is approximately 250 entities. About two-third of these entities are investor-owned utilities and one-third is a combination of municipal and cooperative organizations.

The Public Reporting burden for the requirements contained in the Final Rule is as follows:

Data Collection	No. of Respondents	No. of Responses	Hours Per Respondent	Total Annual Hours
FERC-725D				
Investor-Owned Utilities	170	1	Reporting: 90*	Reporting: 15,300
			Recordkeeping: 210	Recordkeeping: 15,300
Large Municipals and Cooperatives	80	1	Reporting: 90	Reporting: 7,200
			Recordkeeping: 210	Recordkeeping: 16,800
Totals	250			75,000

Total Hours: (Reporting 22,500 hours + Recordkeeping 52,500 hours) = 75,000 hours.

* Hours are attributable to developing SOLs. Recordkeeping pertains to the documentation to be maintained for when audits are conducted.

The Commission estimated that it take approximately 75,000 hours to comply with the 3 Reliability Standards. Of this total, 52, 500 hours would be devoted to recordkeeping. The Commission did not receive any comments in response to its estimates.

13. ESTIMATE OF THE TOTAL ANNUAL COST BURDEN TO RESPONDENTS

Information Collection Costs: It has projected the costs to be:
(a) average annualized cost total annual hours (reporting) 22,500 times $120 = $ $2,700,000.
(b) average annualized cost total annual hours (recordkeeping) = 52,500 @ $40/hour = $2,100,000
Labor Rates: (file/record clerk @ $17 an hour + supervisory @23 an hour)
Storage 1,800 sq. ft. x $925 (off site storage) = $1,665,000

Total costs = $6,465,000.

The Commission believes that this estimate may be conservative because most if not all of the applicable entities currently perform SOL calculations and the proposed Reliability Standards will provide a common methodology for those calculations.

As noted above, the Commission projected total costs of $6,465,000 to comply with the three Reliability Standards and it did not receive any comments challenging its estimates. As the Commission noted in the final rule, most if not all of the applicable entities currently perform SOL calculations and the proposed Reliability Standards will provide a common methodology for those calculations.

14. ESTIMATED ANNUALIZED COST TO FEDERAL GOVERNMENT

The estimate of the cost to the Federal Government is based on salaries for professional and clerical support, as well as direct and indirect overhead costs. Direct costs include all costs directly attributable to providing this information, such as administrative costs and the cost for information technology. Indirect or overhead costs are costs incurred by an organization in support of its mission. These costs apply to activities which benefit the whole organization rather than anyone particular function or activity. It is difficult to provide an assessment at this stage of what the costs will be to the Commission in its review and of Reliability Standards submitted to it. These requirements are at the preliminary stages and the Regional Entities and Regional Advisory bodies are being created. Both organizations will play a role in standards development prior to their submission to the Commission.

Initial Estimates anticipate that 1.5 FTE's will review these Reliability standards at the Commission or a total cost of 1.5 x $126,384 = $189,576.[39]

15. REASONS FOR CHANGES IN BURDEN INCLUDING THE NEED FOR ANY INCREASE

This is a new information collection requirement that implements the provisions of the Electricity Modernization Act of 2005. The Act created section 215 of the Federal Power Act which provides for a system of mandatory reliability rules developed by the ERO, established by the Commission, and enforced by the Commission, subject to Commission review. The three Reliability Standards, as adopted, will implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the three proposed Reliability Standards will ensure that system operating limits or SOLs used in the reliability planning and operation of the Bulk-Power System are determined based on an established methodology.

39 An FTE = Full Time Employee. The $126,384 "cost" consists of approximately $102,028 in salaries and benefits and $24,356 in overhead. The Cost estimate is based on the estimated annual allocated cost per Commission employee for Fiscal Year 2008.

16. **TIME SCHEDULE FOR THE PUBLICATION OF DATA**

The filed proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM07-3-000 and the Commission will require that all Commission-approved Reliability Standards be available on the ERO's website, with an effective date (http://www.nerc.com/~filez/nerc_filings_ferc.html).

Entities will have to file one time to initially comply with the rule, and then on occasion as needed to revise or modify. In addition, annual and three-year self-certification requirements will apply.

Copies of the filings are made available to the public within two days of submission to FERC via the Commission's web site. There are no other publications or tabulations of the information.

17. **DISPLAY OF THE EXPIRATION DATE**

It is not appropriate to display the expiration date for OMB approval of the information collected. The information will not be collected on a standard, preprinted form which would avail itself to that display. Rather the Electric Reliability Organization must prepare and submit filings that reflect unique or specific circumstances related to the Reliability Standard. In addition, the information contains a mixture of narrative descriptions and empirical support that varies depending on the nature of the transaction.

18. **EXCEPTIONS TO THE CERTIFICATION STATEMENT**

Item No. 19(g) (vi) see Instruction No. 17 above for further elaboration. In addition, the data collected for this reporting requirement is not used for statistical purposes. Therefore, the Commission does not use as stated in item no. 19(i) "effective and efficient statistical survey methodology." The information collected is case specific to each Reliability Standard.

B. COLLECTION OF INFORMATION EMPLOYING STATISTICAL METHODS.

This is not a collection of information employing statistical methods.

Commission Directed Revisions to Violation Risk Factor Assignments

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
FAC-010-1	R2	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	LOWER	Explanatory Text	-----
FAC-010-1	R2.1	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage	MEDIUM	HIGH	3 (Consistent

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
		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.			with FAC-011-1 R2.1)
FAC-010-1	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.	MEDIUM	HIGH	3 (Consistent with FAC-011-1 R2.2)
FAC-010-1	R3.6	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	LOWER	MEDIUM	3 (Consistent with FAC-011-1 R3.7)
FAC-011-1	*R2	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	MEDIUM	Explanatory Text	-----
FAC-011-1	*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.	MEDIUM	HIGH	-----
FAC-011-1	*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.	MEDIUM	HIGH	-----
FAC-011-1	R3.4	Level of detail of system models used to determine SOLs.	Not assigned	LOWER	3 (Consistent with FAC-010-1 R3.3)