Supporting Statement for

FERC-725D, Facilities Design, Connections and Maintenance Reliability Standards

As Proposed in Docket No. RM08-11-000

(A Final Rule Issued March 19, 2009)

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 an existing Commission data collection, (filing requirements), as contained in 18 Code of Federal Regulations, Part 40.

FERC-725D is an information collection requirement that implements standards that were previously part of a voluntary program. There are no changes to the information collection burden as reported in an earlier Commission submission. (See ICR 200801-1902-002)

The three revised Reliability Standards, designated as FAC-010-2, FAC-011-2 and FAC-014-2, set requirements for the development and communication of system operating limits of the Bulk Power System (see diagram below) for use in the planning and operation horizons. Compliance with these Reliability Standards will be mandatory and enforceable for the applicable categories of entities identified in each Reliability Standard. These Reliability Standards are approved by the Commission in accordance with its authority under section 215 of the Federal Power Act (FPA), which authorizes the Commission to approve a Reliability Standard developed by the North American Electric Reliability Corporation (NERC). The Commission certified NERC as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. The Commission approves Reliability Standards if the Commission determines that the standard(s) 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]

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).

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 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.

Unlike water or gas, electricity cannot be stored. It must be generated and then used immediately. In addition, electricity follows the "path of least resistance, so electricity cannot re routed in a specific direction. This means that generation and transmission operations in North America must be monitored and controlled in real-time, 24 hours a day, to ensure a consistent and ample flow of electricity. This requires the cooperation and coordination of hundreds of electric industry participants.

On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[3] Pursuant to 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 applies 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 may also, among other actions, direct the ERO to modify an approved Reliability Standard to address a specific matter if it

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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.

considers this appropriate to carry out section 215 of the FPA.[6] Only Reliability Standards approved by the Commission will become mandatory and enforceable.

A Reliability Standard defines obligations or requirements of utilities and entities that operate, plan or use the bulk power system in North America. Meeting these requirements helps ensure the reliable planning and operation of the Bulk Power System. Each 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 are developed by industry following a process managed by the NERC Standards Committee. The process is certified by the American National Standards Institute (ANSI) as open, inclusive, balanced and fair, and is based on the procedures of standards-setting organizations in the United States and Canada. The process is intended to develop consensus on the need for the standard, and the standard itself.

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:

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).

In addition, NERC proposed the addition or revision of several 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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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).

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

These three new Reliability Standards set requirements for the development of system operating limits of the Bulk-Power System for use in the planning and operation horizons. [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.

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On December 27, 2007 the Commission approved the three Reliability Standards concerning version one of Facilities Design, Connections and Maintenance (FAC) that were developed by the NERC/ERO. In addition, the Commission directed the ERO to develop a modification to one of the three Reliability Standards that was approved as mandatory and enforceable. The Commission also approved 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 accepted three new terms for the NERC Glossary of Terms Used in Reliability Standards, and sent back another proposed term, and directed 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 corresponded to each Requirement of the proposed Reliability Standards.[10] 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.

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On October 16, 2008, the Commission proposed to approve revisions to the three version one Reliability Standards concerning Facilities Design, Connections and Maintenance (FAC). These revised standards as developed by NERC ("version two") are designated as FAC-010-2, FAC-011-2 and FAC-014-2. These standards direct 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. Version one of the FAC Reliability Standards were approved by the Commission in Order No. 705 (RM07-3-000).

In response to FERC's directives in Order No. 705, NERC submitted on June 30, 2008 for Commission approval three revised FAC Reliability Standards.

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9 The three Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM07-3-000 and on NERC's website, http://www.nerc.com/~filez/nerc_filings_ferc.html.

10 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).

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On March 19, 2009, the Commission approved NERC's three revised Reliability Standards. The three revised Reliability Standards FAC-010-2, FAC-011-2 and FAC-014-2 set requirements for the development and communication of system operating limits of the Bulk Power System for use in the planning and operation horizons.

FAC-011-1

Requirement R2.3.2 of FAC-011-1 ("version 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." NERC asserted that a significant gap between actual and studied conditions (such as a large error in load forecast) could be treated as though it were a contingency under the version 1 of FAC-011-1 Reliability Standard.

In Order No. 705, the Commission disagreed with NERC's reading of FAC-011-1, sub-Requirement R2.3.2 and the interpretation of the phrase "load greater than studied."[11] However, the Commission found that the meaning of Requirement R2.3 and sub-Requirement R2.3.2 was unclear. The Commission conditionally approved FAC-011-1, but directed the ERO to revise the Reliability Standard through the Reliability Standards development process. FERC proposed that NERC could address its concerns by deleting the phrase, "e.g., load greater than studied."

In response, NERC proposed to address the Commission's concern with the phrase "load greater than studied" by revising FAC-011-1 to remove the phrase from Requirement R2.3.2. NERC's justification was that as the phrase served only as an example and its removal does not materially change the requirement or the Reliability Standard. NERC's proposed FAC-011-2 therefore omits the relevant phrase.

Commission Determination

In this Final Rule, the Commission is approving NERC's removal of the phrase "e.g. load greater than studied" from Requirement R2.3.2 of FAC-011-2. NERC's revision in FAC-011-2 appears reasonable and does not appear to change or conflict with the stated requirements set forth in the version one Reliability Standards approved in Order No. 705. The Commission found that the removal was necessary because the operating conditions referred to in sub-Requirement R2.3.2 exacerbated circumstances that were distinct from the actual contingency to be addressed to what is referred to in Requirement R2.3. Also, the Commission does not support treating "load greater than studied" as a contingency. Correcting for load forecast error is not accomplished by treating the error as a contingency, but is treated under other Reliability

11 Order No. 705, 121 FERC ¶ 61,296 at P 70.

Standards.

Glossary

With the version one FAC Reliability Standards, NERC proposed to add the term "Cascading Outages" to its glossary. In Order No. 705, the Commission noted that, although the glossary did not include a definition of Cascading Outages, it included an approved definition of Cascading, which seemed to describe the same concept. The Commission remanded NERC's proposed definition of Cascading Outages 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 also raised specific concerns with NERC's proposed definition of Cascading Outages. However, the Commission allowed NERC to file a revised definition that addresses the Commission's concerns.

NERC's response indicated that it is not revising the definition of Cascading Outage but to address the Commission's concern, it is removing the term from the proposed FAC Reliability Standards. NERC also indicated that when the Reliability Standard drafting team reviewed the term Cascading Outage relative to the term Cascading, a term in the approved NERC Glossary of Terms, there were no intended material differences in the terms. As a result, NERC removed the term Cascading Outage from the proposed FAC-010-2 and FAC-011-2 Reliability Standards and replaced with it with the term Cascading.

Commission Determination

In the Final Rule, FERC is approving NERC's removal of the term Cascading Outage from its FAC Reliability Standards. NERC's revisions to FAC-010-2 and FAC-011-2 appear reasonable and do not appear to change or conflict with the stated requirements set forth in the version one Reliability Standards approved in Order No. 705.

FAC-010-1

Requirement R2.3 of FAC-010-1 provided that the system's response to a single contingency may include, inter alia, "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."[12] In response to a Commission inquiry, NERC clarified that the provision in FAC-010-1, Requirement R2.3 is limited to loss of load that is directly connected to the facilities removed from service as a direct result of the contingency, i.e., consequential load loss.

In Order No. 705, the Commission reiterated its position on the loss of load as it stated in Order No. 693, regarding Reliability Standard TPL-002-0. In Order No. 693, the Commission noted that "allowing for the 30 minute system adjustment period, the system must be capable of

12 Identical language appears in FAC-011-1, Requirement R2.3

withstanding an N-1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures."[13] Order No. 693 directed the ERO to clarify the planning Reliability Standard TPL-002-0 accordingly. The Commission used the same position in Order No. 705. In Order No. 705, FERC approved Reliability Standard FAC-010-1, Requirement R2.3 and directed the ERO to ensure that the clarification developed in response to Order No. 693 is applicable to the FAC Reliability Standards as well.[14]

NERC's response suggested that the revisions to the term "loss of consequential load" are best addressed in the modifications being made to the transmission planning (TPL) family of Reliability Standards in its Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans. NERC reiterated its position that the TPL Reliability Standards define acceptable system performance response and serve as the foundation for the FAC family of Reliability Standards. NERC stated that the term "loss of consequential load" is intrinsic to the scope of Project 2006-02. According to NERC, the Reliability Standard drafting team has already proposed a definition for the term to be presented for approval for inclusion in NERC's Glossary of Terms.[15] NERC stated that this approach will provide the clarity needed.

Commission Determination

The Commission is adopting its NOPR proposal to allow NERC to address revisions to the term "loss of consequential load" in the modification being made to the TPL Reliability Standards. Such revisions will be consistent with the Commission's prior determinations in Order Nos. 693 and 705.[16] The Commission finds that FAC-010-2 and FAC-011-2 are clearly understood as written and clarified in Order No. 705, including its holding with respect to "loss of consequential load,"[17] and that NERC's proposal to deal with "loss of consequential load" in a more-related project is appropriate.

Violation Severity Levels

In the event of a violation of a Reliability Standard, NERC will establish the initial value range for the corresponding base penalty amount. To do so, NERC will assign a violation risk factor for each requirement of a Reliability Standard that relates to the expected or potential impact of a violation of the requirement on the reliability of the Bulk-Power System. In addition, NERC will define up to four violation severity levels - Lower, Moderate, High and Severe - as measurements for the degree to which the requirement was violated in a specific

13 Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1788.
14 Order No. 705, 121 FERC ¶ 61,296 at P 53.
15 On August 14, 2007, the Reliability Standards drafting team posted for comment a draft of Reliability Standard TPL-001-1. NERC, Draft 2 TPL-001-1, Transmission System Planning Performance Requirements Posted for 45-day Comment Period, Project 2006-02, at 2 (2008), available at: http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html.
16 See Order No. 705, 121 FERC ¶ 61,296 at P 53; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1788 & n.461.
17 See id. P 53.

circumstance.

In Order No. 705, the Commission approved 63 of NERC's 72 proposed violation risk factors and directed NERC to file violation severity level assignments before the version one FAC Reliability Standards become effective.[18] Subsequently, NERC developed violation severity levels for each requirement of Reliability Standard, as measurements for the degree to which the requirement was violated in a specific circumstance.

On June 19, 2008, the Commission issued an order approving the violation severity level assignments filed by NERC for the 83 Reliability Standards approved in Order No. 693.[19] In that order, the Commission offered four guidelines for evaluating the validity of the violation severity levels, and ordered a number of reports and further compliance filing to bring the remainder of NERC's violation severity levels into compliance with the Commission's guidelines. The four guidelines are: (1) violation severity level assignments should not have the unintended consequence of lowering the current level of compliance; (2) violation severity level assignments should ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties; (3) violation severity level assignments should be consistent with the corresponding requirement; and (4) violation severity level assignments should be based on a single violation, not a cumulative number of violations.[20] The Commission found that these guidelines will provide a consistent and objective means for assessing, inter alia, the consistency, fairness and potential consequences of violation severity level assignments. The Commission noted that these guidelines were not intended to replace NERC's own guidance classifications, but rather, provide an additional level of analysis to determine the validity of violation severity level assignments.

In response, NERC stated that it developed a full suite of violation severity levels for FAC-010-2, FAC-011-2 and FAC-014-2. NERC noted that it developed these violation severity levels prior to the issuance of the Violation Severity Level Order.[21] NERC requested that the Commission accept its violation severity levels for the version two FAC Reliability Standards even though it has not yet assessed their validity using the four new guidelines established in the Violation Severity Level Order. NERC stated that it is committed to assessing the violation severity levels for the revised FAC Reliability Standards in the six-month compliance filing required by the Violation Severity Level Order.[22] NERC did not submit violation risk factors for these version two FAC Reliability Standards.

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18 Order No. 705, 121 FERC ¶ 61,296 at P 137.

19 North American Electric Reliability Corp., 123 FERC ¶ 61,284 (2008) (Violation Severity Level Order). NERC had not, at that time, submitted violation severity levels for the FAC Reliability Standards at issue in this proceeding.

20 Id. P 17.

21 NERC June 30, 2008 Filing, Docket No. RM07-3-000 at 5.

22 Id. (citing Violation Severity Level Order, 123 FERC ¶ 61,284 at P 42 (requiring NERC, within six months from the issuance of the Violation Severity Level Order, to conduct a review of the approved violation severity levels pursuant to the Commission guidelines, and submit a compliance filing)).

Commission Determination

In general, the Commission is approving the violation severity levels for FAC-010-2, FAC-011-2 and FAC-014-2. However, as pointed out in the NOPR, the Commission finds that NERC's proposed violation severity levels would not meet its guidelines. The Commission is directing modifications to the violation severity levels to form a complete set of violation severity levels in this Final Rule. The Commission notes that NERC has committed to assessing the violation severity levels in the compliance filing required by the Violation Severity Level Order. The Commission's proposals in the NOPR did not preclude NERC from including an assessment of its FAC violation severity levels in its six-month evaluation, and the Commission encouraged NERC to do so. (See item number 8 for further discussion).

A. Justification

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.[23] The Commission's action in this Final Rule is based on its authority pursuant to section 215 of the FPA.

To elaborate on what was said in the Introduction of this submission, 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.

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

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.[24] In response to the outages, the Secretary of Energy convened a task force to advise 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.[25] 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.[26]

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 has stated that these three Reliability Standards ensure that system operating limits and interconnection reliability operating limits are developed using consistent methods and that

24 The Electric Power Outages in the Western United States, July 2-3, 1996, at 76 (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).

25 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.

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

those methods contain certain essential elements.[27] These Reliability Standards have been implemented in a phased schedule because as NERC explained each responsible entity would have 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.

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 Office of Electric Reliability. One task of this office has been to participate in North American Reliability Corporation'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. The Office of Electric Reliability is 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;

27 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.

- 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 stated purpose of the three Reliability Standards and proposed modifications contained in this Final Rule 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."[28] Version 2 addresses the concerns raised by the Commission in Order Nos.693 and 705.

FAC-010-2 (revised FAC010-1) applies to "planning authorities" and requires each planning authority to document its methods for determining system operating limits and to share the calculated limits with reliability entities.[29] Further, FAC-010-2 includes an Interconnection-wide regional difference applicable to the Western Interconnection. The regional difference provides a different, more detailed methodology for the evaluation of multiple contingencies when establishing SOLs. It also provides that "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."

Reliability Standard FAC-010-2 identifies data retention requirements and two sets of Levels of Non-Compliance, one of general applicability and one for the Western Interconnection. FAC-010-2 includes Measures corresponding to each Requirement. It identifies the regional reliability organization as the entity responsible for compliance monitoring.

Reliability Standard FAC-011-2 (revised 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. Additionally, Reliability Standard FAC-011-2

28 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. . . ."

29 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 noted 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, replaced "planning authority" with the new term "planning coordinator."

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

Reliability Standard FAC-014-2 (revised FAC-014-1) requires each reliability coordinator, planning authority, transmission planner and transmission operator to develop and communicate SOL limits in accordance with the methodologies developed pursuant to FAC-010-1 and FAC-011-1. Reliability Standard FAC-014-2 also includes data retention requirements, Levels of Non-Compliance, and Measures corresponding to each Requirement. It identifies the regional reliability organization as the entity responsible for compliance monitoring.

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 is working with the ERO and regional reliability organizations to be able to use the electronic filing of information so the Commission receives timely information.

The 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 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.[30]

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 Reliability Standards approved in this Final Rule will 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 Reliability Standards would apply, qualify as small entities.[31] The Commission does not consider this a

30 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.

31 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

substantial number. Moreover, as discussed above, the modifications to the 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 modifications to the 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 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

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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.

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. However as noted in item no. 12 of this submission, the three Reliability Standards of this Final Rule do not require responsible entities to file information with the Commission.

However, it should be noted that 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 November 24, 2008.

Five parties filed comments in response to the FAC NOPR: NERC, the Midwest Independent System Operator, Inc. (Midwest ISO), the Bonneville Power Administration (BPA), the United States Department of the Interior, Bureau of Reclamation (Bureau of Reclamation), and the Independent Electric System Operator of Ontario (IESO).

NERC requested clarification regarding the Commission's direction in paragraph 24 of the NOPR. In that paragraph, the Commission stated that it is concerned with several of the proposed violation severity levels and then provided two examples. NERC asked the Commission to clarify whether or not this was intended as a generic statement to preface later paragraphs of the NOPR. NERC also asked if the Commission had identified additional violation severity levels that need revision beyond those identified in the body of the NOPR.

As a general matter, IESO supported the NERC's proposed modifications to the FAC Reliability Standards, including the associated violation risk factors and violation severity levels and asked the Commission to accept them as filed. IESO stated that the violation risk factors and violation severity levels were developed in a stakeholder process with active industry participation through NERC's standards development process. IESO contends that the industry has the resources, technical capability, and the experience necessary to develop violation risk factors and violation severity levels that reflect the requirements embedded in the various reliability standards. IESO recommended that the Commission accept the industry developed and balloted violation risk factors and violation severity levels where these are established by NERC and the industry in adherence to a timely and due process.

By contrast, the Bureau of Reclamation advocated that because the violation severity levels require additional work, the Commission should not approve NERC's proposed Reliability Standards. The Bureau of Reclamation stated that the Commission relies on NERC to develop Reliability Standards and in the event a standard is found to be inadequate, the Commission should remand the standard back to NERC. The Bureau of Reclamation asked the Commission to rely on the existing version until the proposed changes are made and resubmitted to the Commission for approval. Otherwise, the Bureau of Reclamation contends, it will be difficult for regulating entities to enforce uncertain Reliability Standards.

Commission Determination

In response to NERC's comment, the Commission clarifies its statement in paragraph 24 of the NOPR that it is concerned with several of the proposed violation severity levels that was intended as a generic statement to preface later paragraphs. In general, the Commission approves the violation severity levels proposed by NERC. As discussed in the NOPR, however, the Commission identified several violation severity levels that appeared either unclear or inconsistent with the Commission's guidelines for violation severity levels. In this final rule, the Commission approves certain violation severity levels as proposed by NERC and directs certain modifications.

The Commission disagrees with IESO's proposal that because the violation severity levels proposed by NERC in the NOPR were developed by industry participants through NERC's standard development process, the Commission should approve the violation severity levels as filed. The Commission has previously determined that, similar to violation risk factors, violation severity levels are not part of the Reliability Standard and, thus, are appropriately treated as an appendix to NERC's Rules of Procedure.[32] Revisions of violation severity levels do not modify the Reliability Standard. Accordingly, NERC is not required to comport with the Reliability Standards development provisions of Federal Power Act section 215 when revising a violation severity level assignment.[33] It is for this reason that the Commission also rejects the Bureau of Reclamation's request that the Commission not approve the proposed Reliability Standards because the proposed violation severity levels applicable to them require additional work.

32 Violation Severity Level Order, 123 FERC ¶ 61,284 at P 15.
33 See North American Electric Reliability Corporation, 120 FERC ¶ 61,145 at P 16.

FAC-014-2, Requirement R6

Requirement R6 of FAC-014-2 requires a planning authority to identify the subset of multiple contingencies (if any) from Reliability Standard TPL-003, which results in stability limits. Requirements R6.1 and R6.2 require that the planning authority provide the list to the reliability coordinator, or if no multiple contingencies exist, to notify the reliability coordinator, respectively. NERC assigned violation severity levels based on a combination of compliance scenarios relevant to Requirements R6.1 and R6.2.

In the NOPR, the Commission expressed concern that the violation severity levels assigned to FAC-014-2 Requirement R6 does not address a scenario where the planning authority fails to provide a complete subset of contingencies to the reliability coordinator and proposed a revision of the violation severity level assignments. The Commission expressed concern that this omission could prevent the reliability coordinator from having the information it needs for its situational awareness that system operating limits and interconnection reliability operating limit that impact the reliable operation of the Bulk-Power System are being exceeded. The Commission therefore proposed to direct the ERO to add the following "Lower" violation severity level: "The Planning Authority failed to provide a complete subset of contingencies to the reliability coordinator in accordance with R6." The Commission also proposed to direct the ERO to reassign NERC's current "Lower" violation severity level as the new "Moderate" violation severity level to emphasize the need to notify the reliability coordinator.[34] The Commission stated that the proposed revisions would make the violation severity level assignments for Requirement R6 consistent with NERC's own guidelines for the development of violation severity levels related to communication or coordination requirements.[35]

NERC disagreed with the Commission's assertion that the proposed violation severity levels for Requirement R6 of FAC-014-2 do not identify a situation where a planning authority fails to provide a complete subset of contingencies to the reliability coordinator. NERC contends that the "High" and "Severe" violation severity levels for Requirement R6 of FAC-014-2 satisfy the Commission's concerns by stating that the planning authority identified the subset of multiple contingencies which result in stability limits but did not provide the list of multiple contingencies and associated limits to one or more reliability coordinators that monitor the facilities associated with these limits. NERC contends that a planning authority will fail to comply with Requirement R6.1 of FAC-014-2 if they do not provide the complete list set of contingencies to the reliability coordinator.

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34 NERC did not propose a "Moderate" violation severity level for requirement R6.

35 NERC, Violation Severity Level Guidelines Criteria, Project 2007-23 at 19 (2008), available at: http://www.nerc.com/docs/standards/sar/VSLDT_Guidelines_Final_Draft_08Jan08.pdf. The NERC Guidelines indicate that a Moderate violation severity level should be selected when the responsible entity's coordination/communication is non-compliant with respect to at least one significant element within the requirement. In this case, the significant element is the failure to notify the Reliability Coordinator.

The Bureau of Reclamation and IESO separately take issue with the Commission's proposed revisions to violation severity levels applicable to Requirement R6 of FAC-014-2. The Bureau of Reclamation contends that the Commission's proposal would require auditors to perform studies independent from the planning authority in order to determine whether all contingencies were considered. IESO contends that both the "High" and "Severe" violation severity levels address the planning authority's failure to communicate multiple contingency scenarios to the reliability coordinator. IESO, however, agrees with the Commission that there should not be a gap in the violation severity levels and states that the "Lower" violation severity level for FAC-014-2 Requirement R6 should be assigned a "Moderate" violation severity level.

Commission Determination

The Commission agrees with NERC that a planning authority's requirement to provide the reliability coordinator with a complete set of contingencies is addressed in the "High" and "Severe" violation severity levels assigned to Requirement R6 of FAC-014-2. However, the Commission also believes that it is appropriate to apply a binary, pass/fail approach to the violation severity levels because a planning authority either will or will not satisfy this requirement. As proposed by NERC, violations of the sub-requirements are addressed only in the violation severity levels assigned to the main requirement. In keeping with the Commission's decision that the ERO must assign a violation severity level to every sub-requirement, the Commission adopts the NOPR proposal and directs the ERO to assign binary violation severity levels to Requirement R6 and sub-requirements R6.1 and R6.2. Although the enforcement of Requirement R6, and its sub-requirements, may require the use of auditors, this is a compliance issue best addressed on a case-by-case basis in the context of a compliance proceeding.

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 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. The Commission did not receive any comments concerning its burden estimates.

> 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 modifications to the Reliability Standards are minor and, therefore, they do not add to or increase entities' reporting burden. Thus, the modified Reliability Standards do not materially affect the burden estimates relating to the earlier version of the Reliability Standards presented in Order No. 705. Therefore, the Commission will use the same estimates that it used in Order No. 705. The Public Reporting burden for the requirements as contained in the Order

No. 705 were 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's estimates regarding the number of respondents are 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.

13. ESTIMATE OF THE TOTAL ANNUAL COST BURDEN TO RESPONDENTS

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements. It projected the costs in Order No. 705 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 believed that this estimate might 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. Because, these Reliability Standards are still relatively new and the changes proposed here are relatively minor, the Commission will retain the same cost estimates as expressed in the Order No. 705 submission.

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 were anticipated to be 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.[36] As noted in item no. 13 above, the implementation of these Reliability Standards is a relatively recent occurrence and so the Commission will retain the same cost estimates as it stated in the Order No. 705 submission. However, there is an adjustment to reflect the most recent cost of living adjustment to employees' salaries and benefits. The Commission will retain the same estimate in this submission.

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

This submission reflects minor revisions to a recent information collection requirement implementing 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 proposed modifications of the three Reliability Standards, as adopted, would 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 proposed modification of the Reliability Standards would 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. The approved Reliability Standards will not be a burden on the industry since most if not all of the

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36 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.

applicable entities currently perform system operating limit calculations and the approved Reliability Standards will simply provide a common methodology for those calculations.

16. TIME SCHEDULE FOR THE PUBLICATION OF DATA

The filed proposed modifications to the Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM08-11-000 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.

Attachment A.

The three Reliability standards as implemented by NERC are identified below with highlighted text identifying information collection requirements.

A. Introduction

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, 2007

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.

Standard FAC-011-1 — System Operating Limits Methodology for the Operations Horizon
Adopted by Board of Trustees: November 1, 2006. Effective Date: October 1, 2007

A. Introduction

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, 2007

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.

A. Introduction

1. Title: Transfer Capability Methodology
2. Number: FAC-012-1
3. Purpose: To ensure that Transfer Capabilities 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 required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
4.2. Planning Authority required by its Regional Reliability Organization to establish interregional and intra-regional Transfer Capabilities
5. Effective Date: August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).
R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.
R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:
R1.3.1. Transmission system topology
R1.3.2. System demand
R1.3.3. Generation dispatch
R1.3.4. Current and projected transmission uses
R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:
R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.
R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.
R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.
R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:
R3.1. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.
R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or 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 Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator's methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.
M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.
M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.
M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each 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 finding of noncompliance.

1.3. Data Retention
The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability 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 and Reliability Coordinator shall each 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 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

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

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

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

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. 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.