2007, with minor corrections applied on November 16, 2007);

(11) Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ–013, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007).

* * * * *

Note: The following statement will not appear in the Code of Federal Regulations.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM05–5–005]

Standards for Business Practices and Communication Protocols for Public Utilities

April 21, 2008.

WELLINGHOFF, Commissioner, *concurring:*

Today, the Commission issues a Notice of Proposed Rulemaking (NOPR) proposing to amend its regulations under the Federal Power Act [43] to incorporate by reference, among other matters, the latest version of certain business practice standards concerning the Open Access Same-Time Information Systems (OASIS) adopted by the Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB).[44] I appreciate NAESB's leadership and the work of the industry in developing these business practice standards.

One of the business practice standards addressed in this NOPR, WEQ–001 Version 1.4, revises NAESB's Business Practices for OASIS and, among other matters, addresses the information that is to be posted on OASIS. This information includes posting of ancillary service offerings and prices and the process for customers to procure ancillary services.

I write separately to note that in Order No. 890, the Commission determined that many ancillary services may be provided by generating units as well as other non-generation resources such as demand resources where appropriate.[45] Nothing in WEQ–001 precludes such a role for demand resources, but the definition of certain ancillary services in the standard also does not specifically reflect that possible role.

To remove any confusion between the *pro forma* tariff that the Commission adopted in Order No. 890 and the business practice standards for offering and procuring ancillary services on OASIS, I encourage NAESB and its stakeholders to amend WEQ–001, as soon as possible, to reflect that the above-noted ancillary services may be provided by non-generation resources such as demand resources. This will facilitate implementation of this aspect of the *pro forma* OATT.

For this reason, I concur with this NOPR.

Jon Wellinghoff,
Commissioner.

[FR Doc. E8–9046 Filed 4–25–08; 8:45 am]

BILLING CODE 6717–01–P

[43] 16 U.S.C. 791a, *et. seq.*

[44] In addition, the Commission proposes in this NOPR to incorporate by reference NAESB's new business practices standards on transmission loading relief (TLR) for the Eastern Interconnection. I note my concurrence to the separate, concurrently issued NOPR in Docket No. RM08–7–000, in which the Commission proposes to approve, among other matters, modified Reliability Standard IRO–006–4 pertaining to TLR procedures to which the NAESB business practice we address herein relates.

[45] *See* Order No. 890 at P 888 (addressing the following ancillary services: Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalances, Spinning Reserves, Supplemental Reserves, and Generator Imbalances (Schedules 2, 3, 4, 5, 6, and 9, respectively, of the *pro forma* OATT)).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM08–7–000]

Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards

Issued April 21, 2008.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Federal Energy Regulatory Commission proposes to approve six modified Reliability Standards submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC). Five modified Reliability Standards pertain to interchange scheduling and coordination and one pertains to transmission loading relief procedures. In addition, the Commission proposes to approve NERC's proposed interpretations of five specific requirements of Commission-approved Reliability Standards.

DATES: Comments are due June 12, 2008.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- *Agency Web Site: http://www.ferc.gov*. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Patrick Harwood (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

Christopher Daignault (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

SUPPLEMENTARY INFORMATION:

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1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve six modified Reliability Standards submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC). Five modified Reliability Standards pertain to interchange scheduling and coordination, and one pertains to transmission loading relief procedures.[2] In addition, the Commission proposes to approve NERC's proposed interpretations of five specific requirements of Commission-approved Reliability Standards.

I. Background

A. EPAct 2005 and Mandatory Reliability Standards

2. Section 215 of the FPA 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 by the Commission independently.[3]

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO[4] and, subsequently, certified NERC as the ERO.[5] On April 4, 2006, as modified on August 28, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a final rule, Order No. 693, approving 83 of these 107 Reliability Standards and directing other action related to these Reliability Standards.[6] In addition, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards.[7]

[1] 16 U.S.C. 824o (Supp. V 2005).

[2] The Commission is not proposing any new or modified text to its regulations. Rather, as set forth in 18 CFR Part 40, a proposed Reliability Standard will not become effective until approved by the Commission, and the ERO must post on its Web site each effective Reliability Standard.

[3] *See* FPA 215(e)(3), 16 U.S.C. 824o(e)(3) (Supp. V 2005).

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

[5] *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), *appeal docketed sub nom. Alcoa, Inc.* v. *FERC*, No. 06–1426 (D.C. Cir. Dec. 29, 2006).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[7] 16 U.S.C. 824o(d)(5) (Supp. V 2005). Section 215(d)(5) provides, ''The Commission * * * may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard

Continued

4. In April 2007, the Commission approved delegation agreements between NERC and each of the eight Regional Entities, including the Western Electricity Coordinating Council (WECC).[8] Pursuant to such agreements, the ERO delegated responsibility to the Regional Entities to carry out compliance monitoring and enforcement of the mandatory, Commission-approved Reliability Standards. In addition, the Commission approved as part of each delegation agreement a Regional Entity process for developing regional Reliability Standards.

5. NERC's Rules of Procedure provide that a person that is ''directly and materially affected'' by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[9] The ERO's ''standards process manager'' will assemble a team with relevant expertise to address the clarification and also form a ballot pool. NERC's Rules provide that, within 45 days, the team will draft an interpretation of the Reliability Standard, with subsequent balloting. If approved by ballot, the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authority for regulatory approval.

B. NERC Filings

6. This rulemaking proceeding consolidates and addresses three NERC filings.

7. On December 19, 2007, NERC submitted for Commission approval interpretations of requirements in four Commission-approved Reliability Standards: BAL–001–0 (Real Power Balancing Control Performance), Requirement R1; BAL–003–0 (Frequency Response and Bias), Requirement R3; BAL–005–0 (Automatic Generation Control), Requirement R17; and VAR–002–1 (Generator Operation for Maintaining Network Voltage Schedules), Requirements R1 and R2.[10]

8. On December 21, 2007, NERC submitted for Commission approval modifications to Reliability Standard IRO–006–4 (Reliability Coordination—Transmission Loading Relief) that applies to balancing authorities, reliability coordinators, and transmission operators. NERC states that the modifications ''extract'' from the Reliability Standard the business practices and commercial requirements from the current IRO–006–3 Reliability Standard. The business practices and commercial requirements have been transferred to a North American Energy Standards Board (NAESB) business practices document. The NAESB business practices and commercial requirements have been included in Version 001 of the NAESB Wholesale Electric Quadrant (WEQ) Standards which NAESB filed with the Commission on the same day, December 21, 2007.[11] Further, NERC states that the modified Reliability Standard includes changes directed by the Commission in Order No. 693 related to the appropriateness of using the transmission loading relief (TLR) procedure to mitigate violations of interconnection reliability operating limits (IROLs).[12]

9. On December 26, 2007, NERC submitted for Commission approval modifications to five Reliability Standards from the ''Interchange Scheduling'' group of Reliability Standards: INT–001–3 (Interchange Information); INT–004–2 (Dynamic Interchange Transaction Modifications); INT–005–2 (Interchange Authority Distributes Arranged Interchange); INT–006–2 (Response to Interchange Authority); and INT–008–2 (Interchange Authority Distributes Status). NERC states that the modifications to INT–001–3 and INT–004–2 eliminate waivers requested in 2002 under the voluntary Reliability Standards regime for entities in the WECC region. According to NERC, modifications to INT–005–2, INT–006–2, and INT–008–2 adjust reliability assessment time frames for proposed transactions within WECC.[13]

10. Each Reliability Standard that the ERO proposes to interpret or modify in this proceeding was approved by the Commission in Order No. 693.

II. Discussion

11. The Commission discusses below the ERO's proposed interpretations and proposed modifications, and the Commission's proposed disposition of each.

A. NERC's December 19, 2007 Filing: Interpretations

12. As mentioned above, NERC submitted for Commission approval interpretations of four Commission-approved Reliability Standards.

1. BAL–001–0–Real Power Balancing Control Performance and BAL–003–0–Frequency Response and Bias

a. Background

i. Reliability Standard BAL–001–0

13. The purpose of Reliability Standard BAL–001–0 is to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.[14] Requirement R1 of BAL–001–0 defines the limits on area control error (ACE), which essentially is the mismatch between generation and load (*i.e.*, the mismatch between supply and demand) within the footprint of a balancing authority, measured by the difference between the balancing authority's net actual interchange and scheduled interchange with neighboring balancing authorities, after taking into account effects of deviations in interconnection frequency.[15] The ability to constantly match load and generation within a certain tolerance directly affects the electrical state and control of the Bulk-Power System.[16] Each balancing authority thus monitors the extent of its ACE in real-time and takes appropriate action also in real-time to rebalance supply and demand.[17] Requirement R1 obliges each balancing authority, on a rolling twelve-month

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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 this section.''

[8] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[9] NERC Rules of Procedure, Appendix 3A (Reliability Standards Development Procedure), at 26–27.

[10] In its filing, NERC identifies the Reliability Standards together with NERC's proposed interpretations as BAL–001–0a, BAL–003–0a, BAL–005–0a, and VAR–002–1a.

[11] NAESB December 21, 2007 Filing, Docket No. RM05–5–005.

[12] An IROL is a system operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk-Power System.

[13] The proposed, modified Reliability Standard addressed in this notice of proposed rulemaking is available on the Commission's eLibrary document retrieval system in Docket No. RM08–7–000 and also on NERC's Web site, *http://www.nerc.com*.

[14] *See* Reliability Standard BAL–001–0. Each Reliability Standard developed by the ERO includes a ''Purpose'' statement.

[15] Generally, a balancing authority within an interconnection has an obligation to do its part to maintain the desired 60 Hertz (Hz) frequency. To achieve this, each balancing authority must keep its generation output (including net imports from neighboring balancing authorities) and load in balance within its footprint. A deviation from the 60 Hz baseline system frequency signals an imbalance in supply and demand. To prevent this imbalance from propagating throughout the interconnection, steps are taken to adjust regulating reserves (generation output and demand-side management) in response to deviations from the 60 Hz optimum. *See North American Electric Reliability Corp.*, 121 FERC ¶ 61,179, at P 17 (2007) (November 16, 2007 Order).

[16] If generation and load is not matched within a balancing authority's area, the resulting imbalance could result in an undue burden on adjacent balancing authorities and, if additional contingencies from disturbances are experienced, may compromise the ability of the Bulk-Power System to recover from those disturbances. *See* November 16, 2007 Order, 121 FERC ¶ 61,179 at P 28.

[17] *See* November 16, 2007 Order, 121 FERC ¶ 61,179 at P 20.

basis, to maintain its clock-minute averages of ACE within a specific limit.

14. A supply/demand imbalance between the interconnection's generation output (including net imports) and load on a real-time basis will result in a deviation from the desired 60 Hz optimum operating frequency of the interconnection. All of the balancing authorities within an interconnection must work together to correct a deviation.[18] They do this by including a frequency bias component in their ACE calculation which indicates how many more or fewer megawatts a balancing authority would have interchanged with neighboring balancing authorities if the actual frequency had been exactly maintained so as to equal to the scheduled frequency. Thus, balancing authorities calculate what their total interchange would have been if the actual frequency had been exactly maintained so as to equal to the scheduled frequency. With this information, the balancing authority can increase or decrease generation within the balancing authority's area to maintain the correct scheduled interchange. The total supply and the demand within an interconnection is balanced by the collective effort of all the balancing authorities in that interconnection to maintain the correct scheduled interchange. In this manner, frequency deviations are minimized, thereby protecting reliability without causing undue burden on any balancing authorities.

ii. Reliability Standard BAL–003–0

15. The purpose of Reliability Standard BAL–003–0 is to provide a consistent method for calculating the frequency bias component of ACE. To accomplish this purpose, it is necessary to rely on historic data from a balancing authority's automatic generation control.[19] Automatic generation control is the equipment that calculates ACE on an ongoing basis and serves as a ''governor'' that adjusts a balancing authority's generation, and demand-side resources where available, from a central location to minimize unscheduled interchange with its neighboring balancing authorities in order to balance ACE. There are several ways that automatic generation control could be set to balance the supply and demand within the balancing authority area. One method is called the ''tie-line frequency bias'' mode of operation. Collective operation in this mode allows balancing authorities' automatic generation control to calculate ACE and adjust the generation in the balancing authority area in a manner that maintains the interconnection frequency and does not result in an undue burden for any balancing authority. In addition, operation in this mode allows a balancing authority to continuously collect its tie-line and frequency data that must be used when the balancing authority annually reviews the frequency bias component of its ACE calculation as specified by BAL–003–0. Requirement R3 of BAL–003–0 requires the use of the tie-line frequency bias mode of operation of automatic generation control, unless such operation is adverse to system interconnection reliability.

b. NERC's Proposed Interpretations

16. NERC further states that, on June 1, 2007, WECC requested that NERC provide a formal interpretation that addresses Requirement R1 of BAL–001–0 and Requirement R3 of BAL–003–0. In particular, WECC asked whether the use of WECC's existing automatic time error correction procedure, which is currently proposed as a regional Reliability Standard, violates Requirement R1 of BAL–001–0 or Requirement R3 of BAL–003–0.

i. Reliability Standard BAL–001–0

17. Requirement R1 of BAL–001–0 provides:

> Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

18. NERC's proposed interpretation of BAL–001–0 Requirement R1 reads:

- The [WECC automatic time error correction or WATEC] procedural documents ask Balancing Authorities to maintain raw ACE for [control performance standard or CPS] reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL–001 Requirement 1.

(NERC December 19, 2007 Filing, Ex. A–2.)

19. As context to its interpretation, NERC explains that BAL–001–0 uses a formula for the ACE calculation equal to the difference in actual and scheduled interchange, less a component based on the frequency bias to adjust for the difference in actual and scheduled frequency, less the meter error.[20] NERC also explains that the WECC automatic time error correction procedure uses the same formula for ACE as defined in BAL–001–0 except with two additional components.[21]

20. NERC maintains that the use of the WECC automatic time error correction procedure for control does not result in a violation of BAL–001–0 Requirement 1, provided that (1) WECC's balancing authorities use the raw and unadjusted ACE for control performance reporting purposes and (2) the raw, unadjusted ACE complies with Requirement R1.

ii. Reliability Standard BAL–003–0

21. Requirement R3 of BAL–003–0 provides:

> Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection Reliability.

NERC's proposed interpretation of BAL–003–0 Requirement R3 reads:

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, [control performance standard] optimization, time control (in single [balancing authority] interconnections).[22]
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation,[23] there is no violation of BAL–003–0 Requirement 3: $ACE = (NI_A—NI_S)—10B\ (F_A—F_S)—I_{ME}$

(NERC December 19, 2007 Filing, Ex. A–3.)

[18] *See* id. P 31.

[19] Automatic generation control refers to an automatic process whereby a balancing authority's mix and output of its generation and demand-side management is varied to offset the extent of supply and demand imbalances reflected in its ACE. November 16, 2007 Order, 121 FERC ¶ 61,179 at P 19 n.14.

[20] *See* NERC December 19, 2007 Filing at 8–9.

[21] *See id.*

[22] The ''flat frequency'' control mode would increase or decrease generation solely based on the interconnection frequency. The ''flat tie'' mode would increase or decrease generation within a balancing authority area depending solely on that balancing authority's total interchange. The ''tie-line frequency bias'' mode combines the flat frequency and flat tie modes and adjusts generation based on the balancing authority's net interchange and the interconnection frequency.

[23] ''CPS1'' refers to Requirement R1 of BAL–001–0.

22. NERC explains that there is no violation of BAL–003–0 Requirement R3, provided that a balancing authority uses the tie-line frequency bias mode as the underlying control mode and the control performance standard (CPS1), per BAL–001–0 Requirement R1, is measured and reported on the associated ACE equation.

c. Commission Proposal

23. The Commission proposes to approve the ERO's formal interpretation of Requirement R1 of BAL–001–0 and Requirement R3 of BAL–003–0.

24. The ERO's interpretation is reasonable because it clarifies that raw ACE must be used in NERC compliance reporting. Reporting of raw ACE is essential because a balancing authority could exceed ACE limits in BAL–001–0 if allowed to report an adjusted ACE that adds or subtracts amounts from the equation. This interpretation upholds the reliability goal of BAL–001–0, Requirement R1 to minimize the frequency deviation of the interconnection by constantly balancing supply and demand. The interpretation also clarifies that an entity may use automatic generation control modes layered on top of the tie-line frequency bias mode as long as the raw ACE is used in NERC compliance reporting. This would permit WECC to implement more stringent time error correction procedures that rely on additional control modes layered on top of the tie-line frequency bias mode of automatic generation control, provided they do not report adjusted ACE which, if reported, could produce ambiguous data used for frequency bias calculations. The interpretation maintains the goal of BAL–003–0, Requirement R3, by providing accurate historic data for frequency bias calculations and by using ACE calculations in automatic generation control that will adjust the generation, or demand-side resources where available, in the balancing authority area in a manner that maintains the interconnection frequency and does not result in an undue burden for any balancing authority. The Commission proposes to approve the ERO's interpretation based on the understanding that a balancing authority, in operating automatic generation control, must use tie-line frequency bias as its underlying control mode unless to do so is adverse to system or interconnection reliability.

25. In Order No. 693, the Commission stated that, according to the available data, the WECC automatic time error correction procedure is more effective in minimizing time error corrections and inadvertent interchange than the Reliability Standard BAL–004–0.[24] Therefore, the ERO's interpretation provides balancing authorities using the WECC automatic time error correction procedure with necessary clarification and certainty in accordance with the continent-wide Reliability Standards BAL–001–0 and BAL–003–0. Accordingly, this interpretation appears to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.

2. BAL–005–0—Automatic Generation Control

a. NERC's Proposed Interpretation

26. Requirement R17 of Reliability Standard BAL–005–0 (Automatic Generation Control) is intended to annually check and calibrate the time error and frequency devices under the control of the balancing authority that feed data into automatic generation control necessary to calculate ACE. Requirement R17 mandates that the balancing authority must adhere to an annual calibration program for time error and frequency devices. The Requirement states that a balancing authority must adhere to minimum accuracies in terms of ranges specified in Hertz, volts, amps, etc., for various listed devices, such as digital frequency transducers, voltage transducers, remote terminal unit, potential transformers, and current transformers.

27. On December 21, 2006, NERC received a request to provide a formal interpretation of Requirement R17 asking whether the only devices that need to be annually calibrated under this requirement are time error and frequency devices, and whether the list of device accuracy is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a ''frequency device''). NERC provided an interpretation clarifying that the intent of BAL–005–0, Requirement R17 is to annually check and calibrate a balancing authority's time error and frequency devices located in the control room against the common reference, and this requirement does not apply to any such devices located outside of the operations control center.

b. Commission Proposal

28. On July 31, 2007, the ERO received a second request for an interpretation of Requirement R17 of BAL–005–0, which asked the ERO to further clarify the ambiguity of what devices are included in the requirement. On April 15, 2008, the ERO submitted another interpretation of Requirement R17 of BAL–005–0 and sought to withdraw its request for Commission approval of the interpretation of Requirement R17 filed in this proceeding on December 19, 2007. Accordingly, the Commission does not plan to act on the initial interpretation. The Commission will act on the April 15 interpretation in a future proceeding.

3. VAR–002–1—Generator Operation for Maintaining Network Voltage Schedules

a. NERC's Proposed Interpretation

29. The stated purpose of Reliability Standard VAR–002–1 is to ensure that generators provide reactive and voltage control necessary to ensure that voltage levels, reactive flows, and reactive resources are maintained within applicable facility ratings to protect equipment and the reliable operation of the interconnection.[25] Specifically, Requirement R1 of Reliability Standard VAR–002–1 provides:

> The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 of this Reliability Standard provides:

> Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

30. NERC states that it received a request to provide a formal interpretation of Requirements R1 and R2 on January 24, 2007. The request for interpretation first asked whether automatic voltage regulator (AVR) operation in the constant power factor or constant Mvar modes complies with Requirement R1.[26] Secondly, the

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[24] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 377.

[25] Most bulk electric power is generated, transported, and consumed in alternating current (AC) networks. AC systems supply (or produce) and consume (or absorb or lose) two kinds of power: real power and reactive power. Real power accomplishes useful work (*e.g.*, runs motors and lights lamps). Reactive power supports the voltages that must be controlled for system reliability. FERC, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, Docket No. AD05–1–000, at 17 (2005), *available at http://www.ferc.gov/legal/staff-reports.asp (Reactive Power Principles)*.

[26] ''Power factor'' is a measure of real power in relation to reactive power. A high power factor means that relatively more useful power is being taken or produced relative to the amount of reactive power. A lower power factor means that there is relatively more reactive power taken than real power. ''Mvar'' is a measure of reactive power equal to one million reactive volt-amperes. *Reactive*

request asked the ERO whether Requirement R2 gives the transmission operator the option of directing the generation owner to operate the AVR in the constant power factor or constant Mvar modes rather than the constant voltage mode.

31. The AVR is designed to automatically adjust generator voltage and/or power-factor to ensure proper grid operational characteristics. Constant voltage mode is the normal mode of operation for AVR and maintains the output voltage at a constant level. The constant power factor mode is a setting of the AVR that causes the generator to output a set ratio of real power to reactive power, whereas the constant Mvar mode is a setting that causes the generator to maintain an output with a constant amount of reactive power.

32. NERC's formal interpretation provides that AVR operation in the constant power factor or constant Mvar modes does not comply with Requirement R1.[27] The interpretation rests on the assumption that the generator has the physical equipment that will allow such operation and that the transmission operator has not directed the generator to run in a mode other than constant voltage. The interpretation also provides that Requirement R2 does give the transmission operator the option of directing the generation operator to operate the AVR in the constant power factor or constant Mvar modes rather than the constant voltage mode.[28]

33. In its transmittal letter, NERC explains that, with respect to the interpretation of Requirement R1, Reliability Standard VAR–002–1 clearly states that the generator operator shall operate with the automatic voltage regulator in service and controlling voltage. The interpretation specifies that this can only be accomplished by using the constant voltage control mode, and using the constant power factor or constant Mvar control is not a true method to control voltage even though it may have some effect on voltage. In addition, NERC explains that Requirement R2 provides for an exemption to this baseline mode of operation to allow the transmission operator the ability to direct the generator operator to use another mode of operation.

b. Commission Proposal

34. The Commission proposes to approve the ERO's interpretation of Requirement R1 and Requirement R2 of VAR–002–1. These interpretations appear to be reasonable and do not appear to change or conflict with the stated responsibilities set forth in the two requirements as approved in Order No. 693. Therefore, this interpretation appears to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.

B. NERC's December 21, 2007 Filing: Modification of TLR Procedure

1. NERC's Proposed Reliability Standard

35. As mentioned above, on December 21, 2007, NERC submitted for Commission approval proposed Reliability Standard IRO–006–4, to modify the current Commission-approved Reliability Standard, IRO–006–3.

a. Background

36. In Order No. 693, the Commission approved the current version of this Reliability Standard, IRO–006–3. This Reliability Standard ensures that a reliability coordinator has a coordinated transmission service curtailment and reconfiguration method that can be used along with other alternatives, such as redispatch or demand-side management, to avoid transmission limit violations when the transmission system is congested. Reliability Standard IRO–006–3 establishes a detailed TLR process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and the severity of the transmission congestion.[29]

37. In addition to approving IRO–006–3, the Commission in Order No. 693 directed the ERO to modify the Reliability Standard to: (1) Include a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations; [30] and (2) identify in a requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure.[31] These directives reflect an observation from the U.S.-Canada Power System Outage Task Force in the August 14, 2003 Blackout Report, which identified that the TLR procedure is often too slow for use in situations where the system has already violated IROLs.[32] In setting forth these directives, the Commission stated that it did not have concerns with the use of the TLR procedure to avoid potential IROL violations.[33]

b. NERC Filing

38. According to NERC, the modifications embodied in proposed Reliability Standard IRO–006–4 represent the first phase of a three-phase project intended to improve the overall quality of IRO–006. In the first phase, NERC extracted the business practices and commercial requirements from the existing IRO–006–3 Reliability Standard and proposes to transfer them into the NAESB business practices.[34] NERC's filing does not seek to modify the remaining reliability requirements of IRO–006, with the exception that the Reliability Standard has been clarified to include the Commission's Order No. 693 directive that using the TLR procedure is not effective to mitigate an actual IROL violation.

39. According to NERC, the second phase of the IRO–006 project will address possible changes to the regional differences associated with the congestion management process used by the PJM Interconnection, L.L.C., the

Power Principles, supra note 16, at 7, 12, 41, 119, 120.

[27] NERC's proposed interpretation of VAR–002–1 Requirement R1 reads:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1? Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

NERC December 19, 2007 Filing, Ex. C–2.

[28] We note, as does NERC, the requesting party's apparent error when it references ''Generation Owner'' instead of the generator operator.

[29] The equivalent interconnection-wide TLR procedures for use in WECC and Electric Reliability Council of Texas (ERCOT) are known as ''WSCC Unscheduled Flow Mitigation Plan'' and section 7 of the ''ERCOT Protocols,'' respectively.

[30] An IROL is a system operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk-Power System.

[31] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 964.

[32] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* at 163 (April 2004) (*Final Blackout Report*), *available at https://reports.energy.gov/.*

[33] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 962.

[34] The NAESB business practices and commercial requirements have been included in Version 001 of the NAESB Wholesale Electric Quadrant standards and filed with the Commission on December 21, 2007. The NAESB filing is the subject of a separate rulemaking in Docket No. RM05–5–005. A notice of proposed rulemaking addressing the NAESB filing is being issued concurrently with the immediate NOPR.

Midwest Independent System Operator, Inc., and the Southwest Power Pool, Inc. In the third phase, NERC plans to completely redraft the Reliability Standard to incorporate further enhancements and changes beyond the separation of reliability and business practices.

40. In its filing, NERC explains that the filed Reliability Standard IRO–006–4 meets the guidance outlined in Order No. 672, used to determine whether a Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[35] In addition, IRO–006–4 includes violation risk factors and violation severity levels that were not provided with IRO–006–3.

41. NERC's proposed IRO–006–4 Reliability Standard consists of five requirements. Proposed Requirement R1 obligates a reliability coordinator experiencing a potential or actual system operating limit (SOL) or IROL violation within its reliability coordinator area to select one or more procedures to provide transmission loading relief. The requirement also identifies the regional TLR procedures in WECC and Electric Reliability Council of Texas (ERCOT). The requirement includes a warning that the TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation and provides alternatives.

42. Proposed Requirement 2 mandates that the reliability coordinator only use a congestion management procedure to which the transmission operator experiencing the SOL or IROL is a party. NERC explains that Requirement R1 and Requirement R2 are assigned a violation risk factor of ''lower'' because they are administrative in nature and are merely intended to describe how a reliability coordinator may choose a procedure to implement TLR.[36] According to NERC, these Requirements are not intended to duplicate the requirements of other Reliability Standards that ensure the system is operated within SOL and IROL limits such as Requirements R3 and R5 of IRO–005–1, which have ''high'' violation risk factors.[37] NERC adds that, provided the reliability coordinator is adhering to the requirements in IRO–005–1, there is no significant risk to the reliability of the Bulk-Power System as a result of a violation of Requirement R1 of IRO–006–4.

43. Proposed Requirement R3 establishes that a reliability coordinator with a TLR obligation from an interconnection-wide procedure follow the curtailments as directed by the interconnection-wide procedure. The requirement includes that a reliability coordinator desiring to use a local procedure as a substitute for curtailments as directed by the interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO. NERC states that a violation risk factor of ''lower'' for Requirement R3 is appropriate because it is intended that an entity could choose alternate actions for relief other than curtailments specified by this requirement to ensure reliability.

44. Proposed Requirement R4 mandates that each reliability coordinator comply with interconnection-wide procedures, once they are implemented, to curtail transactions that cross interconnection boundaries.

45. Proposed Requirement R5 directs balancing authorities and reliability coordinators to comply with applicable interchange-related Reliability Standards during the implementation of TLR procedures. NERC proposes ''medium'' violation risk factors for Requirement R4 and Requirement R5 explaining that, while failure to comply with these requirements could lead the system to an unbalanced scenario, such failure would not pose a ''high'' risk to the system.

46. Finally, NERC explains that four violation severity levels have been assigned to Requirement R1 of IRO–006–4 based on the number of violations of interconnection-wide procedure requirements, and these levels are intended to base violation severity on the degree of deviation from the requirements by the violator. NERC states that there is a single violation severity level for each of the remaining requirements (*i.e.*, R2, R3, R4, and R5), because an entity simply either ''passes'' or ''fails'' each of these requirements.

c. Commission Proposal

47. The Commission proposes to approve Reliability Standard IRO–006–4 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. In addition, the Commission proposes to direct the ERO to modify certain violation risk factors that correspond to the Requirements of the Reliability Standard.

i. Requirements

48. NERC's proposal implements the Commission's directives (1) to include a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations; and (2) to identify in a requirement the available alternatives to mitigate an IROL violation. Specifically, Requirement R1.1 of IRO–006–4 states, ''The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.'' The Commission proposes to approve this standard based on the interpretation that using a TLR procedure alone to mitigate an IROL violation is a violation of the Reliability Standard.

49. Further, the proposed division between NERC and NAESB business practices seems to be reasonable and appears to pose no harm to reliability. The Commission has long supported the coordination of business practices and Reliability Standards. As early as May 2002, the Commission urged the industry expeditiously to establish the procedures for ensuring coordination between NAESB and NERC.[38] The Commission asks for comments on whether any compromise in the reliability of the Bulk-Power System may result from the removal and transfer to NAESB of the business-related issues formerly contained in Reliability Standard IRO–006.

ii. Violation Risk Factors

50. Violation risk factors delineate the relative risk to the Bulk-Power System associated with the violation of each Requirement and are used by NERC and the Regional Entities to determine financial penalties for violating a Reliability Standard. NERC assigns a lower, medium, or high violation risk factor for each mandatory Reliability Standard Requirement.[39] The Commission also established guidelines for evaluating the validity of each Violation Risk Factor assignment.[40]

[35] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 326.

[36] Exhibit A (Reliability Standard Proposed for Approval) of NERC's December 21, 2007 filing, however, contains the violation risk factor of ''medium'' for these requirements, but NERC indicates elsewhere that it is ''lower.'' NERC December 21, 2007 Filing at 12–13.

[37] *Id.* at 13.

[38] *Electricity Market Design and Structure,* 99 FERC ¶ 61,171, at P 22 (2002); *see also Standards for Business Practices and Communication Protocols for Public Utilities,* Order No. 676, FERC Stats. & Regs. ¶ 31,216, at P 6 (2006).

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

[40] The guidelines are: (1) Consistency with the conclusions of the Blackout Report; (2) consistency

51. The Commission is concerned regarding the violation risk factors submitted with IRO–006–4. While the approved violation risk factors for IRO–006–0 Requirement R2 through Requirement R6 are all ''high,'' [41] NERC proposes to revise violation risk factors for similarly-worded Requirements R1 through R5 of IRO–006–4 to ''lower'' or ''medium.'' Sub-requirements R1.1 through R1.3 are explanatory text; therefore, we propose that a violation risk factor need not be assigned to them. For consistency with the Commission's five guidelines discussed above, the Commission proposes to direct the ERO to modify the violation risk factors assigned to Requirements R1 through R4 to ''high.'' We discuss our concerns below.

52. The Commission disagrees with the ERO that Requirement R1 is administrative in nature in describing how a reliability coordinator may choose a procedure to provide transmission loading relief. Requirement R1, as well as Requirement R2 through R4, goes beyond merely providing procedural choices for transmission loading relief, as the ERO asserts. Requirements R1 through R4 require that a reliability coordinator choose and follow the appropriate procedure to provide relief. If the reliability coordinator chooses an unapproved and ineffective procedure for relief or fails to choose a procedure entirely, potential or actual IROLs will not be mitigated as intended by the reliability coordinator. Failure to implement the proper TLR procedure likely would lead to IROL violations, which could lead to cascading outages. The implementation of the TLR procedure shares a similar reliability goal as other Reliability Standard requirements that keep the transmission system within IROLs, thus presenting a similar reliability risk and violation risk factor, if violated.

53. With respect to IRO–006–4, Requirement R1, the ERO states that, provided the reliability coordinator is adhering to the requirements in IRO–005–1, there is no significant risk to the reliability of the Bulk-Power System as a result of a violation of Requirement R1 of IRO–006–4. We disagree. The violation risk factor of a requirement represents the risk a violation of that requirement presents to the reliability of the Bulk-Power System. Violation risk factors should not be assigned differently for requirements in separate Reliability Standards based on compliance with another standard. Two requirements either achieve separate reliability goals and, therefore, violation of them represents independent risks, or two requirements share the same reliability goal. As stated in Guideline 3 of the Violation Risk Factor Order,[42] the Commission expects that the assignment of violation risk factors corresponding to requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

54. Furthermore, a ''high'' violation risk factor assignment for Requirements R1 through R4 is consistent with findings of the Final Blackout Report. The report highlights that, generally, ''TLRs are intended as a tool to prevent the system from being operated in an unreliable state and are not applicable in real-time emergency situations.'' [43] As a result, Recommendation No. 31 in the Final Blackout Report was developed to clarify that the TLR procedure should not be used in situations involving an actual violation of an operating security limit.

55. A medium or lower violation risk factor has been approved for the Reliability Standards in the Interchange Scheduling and Coordination (INT) family of Reliability Standards. Requirement R5 of IRO–006–4 complements the INT group of Reliability Standards and, thus, appears to be appropriately assigned a medium violation risk factor.

56. The added ''Measures'' and other revisions embedded in proposed Reliability Standard IRO–006–4 do not appear to substantively change the earlier, Commission-approved version (*i.e.*, IRO–006–3).

57. In summary, proposed Reliability Standard IRO–006–4 appears to be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Accordingly, the Commission proposes to approve Reliability Standard IRO–006–4 as mandatory and enforceable. In addition, the Commission proposes to direct the ERO to modify the violation risk factors, as described above.[44]

C. NERC's December 26, 2007 Filing: Modification to Five ''Interchange and Scheduling'' Reliability Standards

58. NERC submitted for Commission approval proposed modifications to five Reliability Standards from the INT group of Reliability Standards.

1. INT–001–3—Interchange Information and INT–004–2—Dynamic Interchange Transaction Modifications

a. Background

59. The Interchange Scheduling and Coordination or ''INT'' group of Reliability Standards address interchange transactions, which occur when electricity is transmitted from a seller to a buyer across the power grid. Reliability Standard INT–001 applies to purchasing-selling entities and balancing authorities. The stated purpose of this Reliability Standard is to ''ensure that Interchange Information is submitted to the NERC-identified reliability analysis service.'' Reliability Standard INT–004 is intended to ''ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.''

60. In Order No. 693, the Commission approved the currently applicable version of these Reliability Standards, INT–001–2 and INT–004–1.[45] Further, when NERC initially submitted these two Reliability Standards for Commission approval, NERC also asked the Commission to approve a ''regional difference'' that would exempt WECC from requirements related to tagging dynamic schedules and inadvertent payback provisions of INT–001–2 and INT–004–1. The Commission, in Order No. 693, stated that it did not have sufficient information to address the ERO's proposed regional difference and directed the ERO to submit a filing either withdrawing the regional difference or providing additional information needed for the Commission to make a determination on the matter.[46] The effect of NERC's December 26, 2007 filing is to withdraw the regional difference with respect to WECC.

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within a Reliability Standard; (3) consistency among Reliability Standards; (4) consistency with NERC's definition of the violation risk factor level; and (5) treatment of requirements that co-mingle more than one obligation. The Commission also explained that this list was not necessarily all-inclusive and that it retains the flexibility to consider additional guidelines in the future. A detailed explanation is provided in Violation Risk Factor Rehearing, 120 FERC ¶ 61,145 at P 8–13.

[41] The violation risk factors for these requirements were submitted by NERC on February 23, 2007, and they were approved in the Violation Risk Factor Order.

[42] 119 FERC ¶ 61,145 at P 25.

[43] *Final Blackout Report* at 62.

[44] Although ''time horizons,'' which relate to the immediacy of the risk posed by a violation of a requirement, are included in this Reliability Standard, we do not propose to rule on the time horizons in this rulemaking. On March 3, 2008, in Docket No. RR08–4–000, NERC submitted proposed violation severity levels corresponding to the Requirements of 83 Commission-approved Reliability Standards. The Commission will address the violation severity levels regarding IRO–006–4 in that proceeding.

[45] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 821, 843. In addition, the Commission directed that the ERO develop modifications to INT–001–2 and INT–004–1 that address the Commission's concerns.

[46] *Id.* P 825.

b. NERC's Proposed Modifications

61. In May 2007, WECC requested that NERC rescind the regional difference, referred to as e-tagging waivers,[47] for Reliability Standards INT–001–2 and INT–004–1. According to NERC, WECC has developed business practices for dynamic schedules and has taken the steps needed to comply with the e-tagging of inadvertent payback interchange schedules. Thus, WECC determined that it no longer needs the e-tagging waivers.

62. NERC processed WECC's request through NERC's Reliability Standard Development Procedure, using its urgent action process.[48] NERC states that, by rescinding the e-tagging waivers, NERC maintains uniformity and makes no structural changes to the requirements in the current Commission-approved version of the Reliability Standards.

c. Commission Proposal

63. NERC states that simply rescinding these waivers will not result in structural changes to the requirements in the current Commission-approved version of the Reliability Standards and will maintain uniformity. Further, we note that WECC agrees that it no longer needs to retain the waivers.[49] Accordingly, the Commission proposes to approve INT–001–3 and INT–004–2.

2. INT–005–2—Interchange Authority Distributes Arranged Interchange

a. INT–006–2—Response to Interchange Authority, and INT–008–2—Interchange Authority Distributes Status

i. Background

64. In Order No. 693, the Commission approved the entire group of INT Reliability Standards.[50]

65. Reliability Standard INT–005–1 applies to the interchange authority. The stated purpose of proposed Reliability Standard INT–005–1 is to ''ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.''

66. Reliability Standard INT–006–1 applies to balancing authorities and transmission service providers. The stated purpose of the Reliability Standard is to ''ensure that each Arranged Interchange is checked for reliability before it is implemented.''

67. Reliability Standard INT–008–1 applies to the interchange authority. The stated purpose of the Reliability Standard is to ''ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.'' This means that it is the interchange authorities' responsibility to oversee and coordinate the interchange from one balancing authority to another.

ii. NERC's Proposed Modifications

68. In its December 26, 2007 filing, NERC addresses a specific reliability need identified by WECC in its urgent action request.

69. Requirement R1.4 of INT–007–1 requires that each balancing authority and transmission service provider provide confirmation to the interchange authority that it has approved the transactions for implementation. NERC states that for WECC the timeframe allotted for this assessment is five minutes in the original version of the Commission-approved Reliability Standards.

70. NERC explains that the proposed Reliability Standards for INT–005–2, INT–006–2, and INT–008–2 would increase the timeframe for applicable WECC entities to perform the reliability assessment from five to ten minutes for next hour interchange tags submitted in the first thirty minutes of the hour before. According to NERC, this modification is needed because the majority of next-hour tags in WECC are submitted between xx:00 and xx:30. NERC explains that the existing five minute assessment window makes it nearly impossible for balancing authorities and transmission service providers to review each tag before the five minute assessment time expires. NERC maintains that, when the time expires, the tags are denied and must be resubmitted.

71. NERC states that WECC has experienced numerous instances of transactions being denied because one or more applicable reliability entities did not actively approve the tag. In NERC's view, the current structure causes frustration and inefficiencies for entities involved in this process, as requestors are required to re-create tags that are denied. Further, NERC states that there is no reliability basis for a five minute assessment period for tags submitted at least thirty minutes ahead of the ramp-in period.

72. NERC notes that, prior to January 1, 2007, when the new INT group of Reliability Standards was implemented, WECC had a ten-minute reliability assessment period for next-hour tags. NERC states that the urgent action request restores assessment times back to ten minutes.

73. Apart from the extension of the reliability assessment period from five to ten minutes for WECC entities, NERC avers that it makes no substantive changes to the requirements in the current Commission-approved version of the Reliability Standards.

b. Commission Proposal

74. The Commission proposes to approve INT–005–2, INT–006–2, and INT–008–2. The only change proposed to these Reliability Standards is the reliability assessment period for WECC.[51]

III. Information Collection Statement

75. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[52] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[53] As stated above, the Commission previously approved, in Order No. 693, each of the Reliability Standards that are the subject of the current rulemaking. The proposed modifications to the Reliability Standards are minor and the proffered interpretations relate to existing Reliability Standards; therefore, they do not add to or increase entities' current reporting burden. Thus, the current proposal would not materially affect the burden estimates relating to the currently effective version of the Reliability Standards presented in Order No. 693.[54]

76. For example, the proposed interpretation of BAL–001–0 and BAL–003–0 does not modify or otherwise affect the collection of information already in place. With respect to BAL–001–0, the interpretation merely clarifies the rule that is already in place, that the time error correction

[47] An E-tag represents a transaction on the North American bulk electricity market scheduled to flow within, between, or across electric utility company territories electronically. This is done so that transmission system operators can ascertain all of the transactions impacting their local system and take any corrective actions to alleviate situations that could put the power grid at risk of damage or collapse.

[48] NERC December 26, 2007 Filing at 5–6.

[49] *Id.*

[50] In addition, the Commission directed the ERO to develop modifications to INT–006–1. The Commission-directed modifications are not included in the immediate filing; rather, the ERO will develop such modifications pursuant to its *Reliability Standards Development Plan 2008–2010.*

[51] The Commission notes that NERC's compliance with Order No. 693, with respect to Reliability Standard INT–006–1, is ongoing. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 866.

[52] 5 CFR 1320.11.

[53] 44 U.S.C. 3507(d).

[54] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1905–07.

component of the WECC automatic time error correction calculation of ACE is not to be used in NERC performance reporting. With respect to BAL–003–0, the interpretation clarifies that layering additional control modes on top of the tie-line frequency bias mode of automatic generation control is acceptable. Layering additional control modes on top of the tie-line frequency bias mode of automatic generation control does not change the information that a balancing authority reports because the same logs, data, or measurements would be maintained.

77. The proposed removal of business practice-related requirements from Reliability Standard IRO–006–4 will likely decrease, not increase, the reporting burden associated with the current, Commission-approved version of the Reliability Standard. Nor would the proposed revision to certain Reliability Standards to allow WECC an additional five minutes to perform a reliability assessment regarding interchange transactions impact the reporting burden. Further, the proposal to rescind the requested waivers from the e-tagging obligation under Reliability Standards INT–001–3 and INT–004–2 for entities in the WECC region does not change the reporting burden because NERC was never granted its requested waiver to exempt WECC from requirements related to tagging dynamic schedules and inadvertent payback.[55] In addition, WECC already has business practice standards in place that fulfill the dynamic transfer e-tagging reporting and record keeping obligations set forth in these Reliability Standards.[56]

78. Thus, the proposed modifications to the current Reliability Standards and interpretations effected by this proposed rule will not increase the reporting burden nor impose any additional information collection requirements.

79. The Commission does not foresee any additional impact on the reporting burden for small businesses, because the proposed modifications are minor and the interpretations do not increase the existing burden. However, we will submit this proposed rule to OMB for informational purposes.

Title: Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards.

Action: Proposed Collection.

OMB Control No.: 1902–0244.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule would approve six modified Reliability Standards, five of which pertain to interchange scheduling and coordination and one that pertains to transmission loading relief procedures. In addition, this proposed rule would approve interpretations of five specific requirements of Commission-approved Reliability Standards. The proposed rule would find the Reliability Standards and interpretations just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Internal Review: The Commission has reviewed the proposed Reliability Standards and interpretations and made a determination that these requirements are necessary to implement section 215 of the FPA. These requirements conform to the Commission's plan for interchange scheduling and coordination as well as transmission loading relief procedures within the energy industry.

80. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov*].

81. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Information and Regulatory Affairs, Washington, DC 20503 [*Attention:* Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–4650, fax: (202) 395–7285, e-mail: *oira_submission@omb.eop.gov*].

IV. Environmental Analysis

82. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[57] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[58] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

83. The Regulatory Flexibility Act of 1980 (RFA)[59] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's Office of Size Standards develops the numerical definition of a small business. (*See* 13 CFR 121.201.) For electric utilities, a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours. The RFA is not implicated by this proposed rule because the minor modifications and interpretations discussed herein will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

84. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 45 days from publication in the **Federal Register**. Comments must refer to Docket No. RM08–7–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

85. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

[55] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 822, 825 (directing ERO either to withdraw regional difference or provide additional information).

[56] *See* Business Practice Standard INT–BPS–008–1 (Dynamic Transfer E-Tagging Requirements), available at *http://www.wecc.biz.*

[57] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[58] 18 CFR 380.4(a)(2)(ii).

[59] 5 U.S.C. 601–12.

Commenters filing electronically do not need to make a paper filing.

86. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC, 20426.

87. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

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

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

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

List of Subjects in 18 CFR Part 40

Electric power, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

Commissioners Wellinghoff and Kelly concurring jointly with a separate statement.

Kimberly D. Bose,

Secretary.

Department of Energy

Federal Energy Regulatory Commission

[Docket No. RM08–7–000]

Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards

Issued April 21, 2008.

WELLINGHOFF and KELLY, Commissioners, *concurring*:

Today, the Commission issues a Notice of Proposed Rulemaking (NOPR) proposing to approve, among other matters, modified Reliability Standard IRO–006–4 pertaining to transmission loading relief (TLR) procedures that can be used to prevent or manage potential or actual transmission line limit violations when the transmission system is congested. An earlier version of this Reliability Standard, IRO–006–3, was approved in Order No. 693 subject to modification.[60] This Reliability Standard establishes a detailed TLR process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transmission transactions based on their priorities and the severity of the transmission congestion. However, the Commission directed the ERO[61] to modify the Reliability Standard to: (1) Include a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations, and (2) identify in a requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure.[62]

Reliability Standard IRO–006–4 contains the required warning that the TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. It furthers states that other acceptable and more effective procedures to mitigate actual IROL violations include reconfiguration, redispatch, or load shedding. Load shedding reduces customers' demand involuntarily.

We write separately to note that demand-side management (DSM), or voluntary demand reduction, is not explicitly included in IRO–006–4 among the acceptable alternatives to TLR procedures. Nothing in the proposed standard precludes the use of DSM that can respond quickly to emergencies as an alternative to TLR procedures. Nor is there any indication that NERC intended this to be an exhaustive list of alternatives. We understand that DSM technologies used currently to provide operating reserve (for instance, in the operating reserve markets of ISO and RTOs) would, in fact, be deployed as quick response to IROL violations and in most cases would be deployed prior to involuntary load shedding. Indeed, voluntary demand response could be a better alternative than involuntary load shedding, which, as we indicated above, IRO–006–4 identifies as an acceptable alternative to TLR procedures.

In Order No. 693, the Commission directed modifications to Reliability Standards BAL–002–0 (Disturbance Control Performance), EOP–002–2 (Capacity and Energy Emergencies), VAR–001–1 (Voltage and Reactive Control), and the sensitivity studies of the TPL (Transmission Planning) standards to explicitly provide that DSM may be used as a resource to meet the requirements of those Standards. The Commission clarified that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.[63] The Commission also addressed why explicit identification in the Reliability Standard is necessary, stating:

> The Commission disagrees with APPA that we should not explicitly identify any type of capacity as a resource for meeting reserve contingencies. The Commission believes that listing the types of resources that can be used to meet contingency reserves makes the Reliability Standard clearer, provides users, owners and operators of the Bulk-Power System a set of options to meet contingency reserves, and treats DSM on a comparable basis with other resources.
>
> Many commenters argue that the Commission's proposed directive that would explicitly allow DSM as a resource for contingency reserves is too prescriptive. Concerns in this area generally fall into three categories: (1) That DSM should be treated on a comparable basis as other resources; (2) that the Reliability Standard should be based on meeting an objective as opposed to stating how that objective is met and (3) that DSM

[60] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693–A, 120 FERC ¶ 61,053 at P 964 (2007).

[61] The Commission designated the North American Electric Reliability Corp. (NERC) as the nation's electric reliability organization (ERO) in 2006.

[62] An IROL is a system operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk-Power System.

[63] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 335.

may not be technically capable of providing this service.

With regard to the first concern, the Commission clarifies that the purpose of the proposed directive is to ensure comparable treatment of DSM with conventional generation or any other technology and to allow DSM to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option. The proposed directive as written achieves that goal. With regard to the second concern, we believe that this Reliability Standard is objective-based and we reiterate that we are simply attempting to make it inclusive of other technologies that may be able to provide contingency reserves, and are not directing the use of any particular type of resource. By specifying DSM as a potential resource for contingency reserves, the Commission is clarifying the substance of the Reliability Standard.[64]

Thus, in the interest of clarity and comparability, we would prefer to see DSM included among the list of alternatives to TLR procedures. Therefore, we would be interested in comments regarding the inclusion of DSM that is capable of responding quickly to emergencies among the alternatives to TLR procedures for mitigating transmission line limit violations to maintain system reliability.

For these reasons, we concur with this NOPR.

Jon Wellinghoff,

Commissioner.

Suedeen G. Kelly,

Commissioner.

[FR Doc. E8–9013 Filed 4–25–08; 8:45 am]

BILLING CODE 6717–01–P

[64] *Id* at P 331–33.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 382

[Docket No. AD08–7–000]

Annual Charges Assessments for Public Utilities

April 21, 2008.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Commission is seeking comments on its current methodology for the assessment of electric annual charges to public utilities, in particular, whether that methodology remains fair and equitable, and on alternative methodologies. As provided in its current regulations, the Commission recovers the costs of its electric regulatory program through filing fees and, as particularly relevant here, annual charges assessed to public utilities that provide transmission service, based on the volume of electricity transmitted. This methodology reflects that regulation of transmission providers, transmission facilities and transmission service is central to Commission regulation, and that the transmission grid is the interstate highway system for wholesale power sales. This Notice will enable the Commission to determine whether its current methodology remains fair and equitable, and to review alternative methodologies.

DATES: Comments are due May 28, 2008.

ADDRESSES: Interested persons may submit comments, identified by Docket No. AD08–7–000, by any of the following methods:

- *eFiling:* Comments may be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. Documents created electronically using word processing software should be filed in the native application or print-to-PDF format and not in a scanned format. This will enhance document retrieval for both the Commission and the public. The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Attachments that exist only in paper form may be scanned. Commenters filing electronically should not make a paper filing. Service of rulemaking (or Notice of Inquiry) comments is not required.
- *Mail/Hand Delivery:* Commenters that are not able to file electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT: For further information contact:

Lawrence R. Greenfield (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6415.

Richard M. Wartchow (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8744.

Troy D. Cole (Technical Information), Director, Division of Financial Services, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6161.

SUPPLEMENTARY INFORMATION:

1. In this Notice of Inquiry, the Commission is seeking comments on its current methodology for the assessment of electric annual charges to public utilities, in particular, whether that methodology remains fair and equitable, and on alternative methodologies.[1] As provided in its current regulations, the Commission recovers the costs of its electric regulatory program through filing fees and, as particularly relevant here, annual charges assessed to public utilities that provide transmission service, based on the volume of electricity transmitted. This methodology reflects that regulation of transmission providers, transmission facilities and transmission service is central to Commission regulation, and that the transmission grid is the interstate highway system for wholesale power sales. This Notice will enable the Commission to determine whether its current methodology remains fair and equitable, and to review alternative methodologies.

2. Although the Commission has held in the past that industry concerns did not justify a change to the annual charges methodology, in response to continued expressions of concern the Commission is issuing this Notice of Inquiry to seek comment on whether the existing methodology remains an appropriate means to recover the costs of the Commission's electric regulatory program or whether there is another more appropriate alternative. The Commission seeks to ascertain whether those industry concerns, although not determinative previously, may now be more valid and, if so, to review alternative proposals for the recovery of the Commission's electric regulatory program costs. The Commission also invites interested parties to submit in this proceeding their views on other possible changes to the Commission's annual charges regulations.

[1] This Notice of Inquiry is limited to the assessment of annual charges to public utilities regulated under Parts II and III of the Federal Power Act (FPA). It does not, therefore, address the assessment of charges for the Commission's hydroelectric, natural gas or oil pipeline regulatory programs. It also does not address recovery of Federal power marketing agency (PMA)-related costs or electric filing fees (the latter are separately charged for, among other things, petitions for declaratory orders, Commission staff interpretations and certain qualifying facility-related filings).