necessary to keep them operationally current. Therefore, this regulation: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under Department of Transportation (DOT) Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of the airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it removes Domestic, Alaskan, and Hawaiian Reporting Points contained in the NAS.

Environmental Review

The FAA has determined that this action qualifies for categorical exclusion under the National Environmental Policy Act in accordance with 311a, FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures.'' This airspace action is not expected to cause any potentially significant environmental impacts, and no extraordinary circumstances exist that warrant preparation of an environmental assessment.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9V, Airspace Designations and Reporting Points, signed August 9, 2011, and effective September 15, 2011, is amended as follows:

Paragraph 7003 Other domestic reporting points.

ABACO: [Removed]

* * * * *

ALLBA: [Removed]

BACUS: [Removed]

* * * * *

BRIMS: [Removed]

CARPS: [Removed]

CATFI: [Removed]

* * * * *

CRABI: [Removed]

* * * * *

EARNS: [Removed]

FLASH: [Removed]

FLORI: [Removed]

GATES: [Removed]

* * * * *

OHIOS: [Removed]

* * * * *

SMELT: [Removed]

SQUID: [Removed]

* * * * *

Paragraph 7004 Alaskan low altitude reporting points.

* * * * *

NESSY: [Removed]

* * * * *

SAVRY: [Removed]

* * * * *

Paragraph 7005 Alaskan high altitude reporting points.

* * * * *

AUGIN: [Removed]

* * * * *

ENCOR: [Removed]

* * * * *

KILLA: [Removed]

* * * * *

NESSY: [Removed]

* * * * *

SAVRY: [Removed]

* * * * *

Paragraph 7006 Hawaiian reporting points.

* * * * *

SHILA: [Removed]

* * * * *

Issued in Washington, DC, March 12, 2012.

Gary A. Norek,

Acting Manager, Airspace, Regulations and ATC Procedures Group.

[FR Doc. 2012–6744 Filed 3–20–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 39 and 40

[Docket No. RM11–16–000; Order No. 759]

Transmission Relay Loadability Reliability Standard

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission approves Reliability Standard PRC–023–2 (Transmission Relay Loadability) submitted by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. The Reliability Standard requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria to ensure that the relays reliably detect—and protect the electric network from—fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. The Commission also approves NERC Rules of Procedure Section 1700—Challenges to Determinations, which provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC–023.

DATES: *Effective Date:* This rule will become effective May 7, 2012.

FOR FURTHER INFORMATION CONTACT:

Kevin Ryan (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–6840.

Kenneth U. Hubona (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 13511 Label Lane, Suite 203, Hagerstown, MD 21740, (301) 665–1608.

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Transmission Relay Loadability Reliability Standard

Docket No. RM11–16–000

Order No. 759

Final Rule

(Issued March 15, 2012)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard PRC–023–2 (Transmission Relay Loadability) submitted by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) certified by the Commission. The Reliability Standard requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria to ensure that the relays reliably detect—and protect the electric network from—fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability.[2] The Commission also approves NERC Rules of Procedure Section 1700—Challenges to Determinations, which provides registered entities a means to challenge determinations made by planning coordinators under Reliability Standard PRC–023.

I. Background

A. Relay Protection Systems

2. Protective relays are devices that detect and initiate the removal of faults on an electric system.[3] They are designed to read electrical measurements, such as current, voltage, and frequency, and can be set to recognize certain measurements as indicating a fault. When a protective relay detects a fault on an element of the system under its protection, it sends a signal to an interrupting device(s) (such as a circuit breaker) to disconnect the element from the rest of the system. Impedance relays, which are the most common type of relays used to protect transmission lines, continuously measure voltage and current on the protected transmission line and operate when the measured magnitude and phase angle of the impedance (voltage/current) falls within the settings of the relay.

B. Reliability Standard PRC–023–1 and Order No. 733

3. Currently effective Reliability Standard PRC–023–1 applies to relay settings on (1) all transmission lines and transformers with low-voltage terminals operated or connected at or above 200 kV; and (2) those transmission lines and transformers with low voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system.[4] The Reliability Standard consists of three Requirements and an Attachment A. Requirement R1 requires entities with certain transmission facilities to set their relays according to one of thirteen specific settings (sub-parts R1.1 through R1.13) designed to maximize loadability while maintaining Reliable Operation of the bulk electric system for all fault conditions. Requirement R2 provides additional obligations for entities that elect certain settings. Requirement R3 requires planning coordinators to designate facilities, operated between 100 kV and 200 kV, that are critical to the reliability of the bulk electric system and are therefore subject to Requirement R1. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements.

4. On March 18, 2010, the Commission issued a Final Rule approving Reliability Standard PRC–023–1 (Transmission Relay Loadability), that requires transmission owners, generator owners, and distribution providers set load-responsive phase protection relays according to specific criteria to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not operate during non-fault load conditions.[5] In addition, under section 215(d)(5) of the FPA, the Commission directed the ERO to develop modifications to the Standard to address certain issues identified by the Commission.

1. Currently Effective Requirement R1

5. Requirement R1 states that each transmission owner, generator owner, and distribution provider subject to Reliability Standard PRC–023–1 shall use one of the criteria prescribed in sub-parts R1.1 through R1.13 for any specific circuit terminal to prevent its phase protective relay setting from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions.

6. In Order No. 733, the Commission directed the ERO, under section 215(d)(5) of the FPA, to develop modifications to Requirement R1 to: (1) Require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-part R1.2;[6] (2) require entities that have protective relays set pursuant to sub-part R1.10 to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault;[7] and (3) require the ERO to document, subject to audit by the Commission, and to make available for review to users, owners, and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-part R1.12.[8]

2. Currently Effective Requirement R2

7. Requirement R2 states that transmission owners, generator owners, and distribution providers that use a circuit with the protective relay settings determined by the practical limitations described in specified R1 sub-parts must use the calculated circuit capability as the circuit's facility rating and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator with the calculated circuit capability.

3. Currently Effective Requirement R3

8. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore subject to Requirement R1. Sub-part R3.1 requires planning coordinators to have a process to identify critical facilities. Sub-part R3.1.1 specifies that the process must

[1] 16 U.S.C. 824o (2006).

[2] In the context of the proposed Reliability Standard, ''loadability'' refers to the ability of protective relays to refrain from operating under all permissible loading conditions on all applicable transmission lines and transformers.

[3] A ''fault'' is defined in the NERC Glossary of Terms used in Reliability Standards as ''[a]n event occurring on an electric system such as a short circuit, broken wire, or an intermittent connection.''

[4] Pursuant to section 40.3 of the Commission's regulations, all Commission-approved Reliability Standards are available on NERC's Web site at *www.nerc.com. See* 18 CFR 40.3.

[5] *Transmission Relay Loadability Reliability Standard,* Order No. 733, 130 FERC ¶ 61,221 (2010), *order on reh'g and clarification,* Order No. 733–A, 134 FERC ¶ 61,127 (2011); *clarified,* Order No. 733–B, 136 FERC ¶ 61,185 (2011).

[6] Order No. 733, 130 FERC ¶ 61,221, at P 186.

[7] *Id.* P 203.

[8] *Id.* P 224.

consider input from adjoining planning coordinators and affected reliability coordinators. Sub-parts R3.2 and R3.3 require planning coordinators to maintain a list of critical facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of initially establishing it, and within 30 days of any subsequent change.

9. In Order No. 733, the Commission directed the ERO to modify Requirement R3 to: (1) Apply an ''add in'' approach to sub-100 kV facilities that are owned or operated by currently registered entities or entities that become registered entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity; [9] (2) specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System; [10] and (3) add the Regional Entity to the list of entities that receive a list of sub-200 kV facilities determined by the planning coordinator to be critical to the reliability of the bulk electric system.[11] In addition, the Commission directed the ERO to develop an appeals process for entities to challenge a criticality determination.[12]

4. Currently Effective Attachment A

10. Attachment A to Reliability Standard PRC–023–1 specifies which protection systems are subject to and excluded from the Standard's Requirements. Section 1 of Attachment A provides that the Reliability Standard applies to any protective functions that can operate with or without time delay, on load current, including but not limited to: (1) Phase distance; (2) out-of-step tripping; (3) switch-on-to-fault; (4) overcurrent relays; and (5) communication-aided protection applications. Section 2 states that the Reliability Standard requires evaluation of out-of-step blocking schemes [13] to ensure that they do not operate for faults during the loading conditions defined in the Standard's Requirements. Finally, section 3 expressly excludes certain relay elements and protection systems from the Reliability Standard's Requirements.

11. The Commission, in Order No. 733, directed the ERO to modify Attachment A to: (1) include section 2 as an additional Requirement with the appropriate violation risk factor and violation severity level in the Reliability Standard; [14] and (2) include supervising relay elements on the list of relays and protection systems that are specifically subject to the reliability Standard.[15]

5. Currently Effective Implementation Plan

12. Reliability Standard PRC–023–1 established staggered effective dates for various Requirements and facilities. The Standard also included a footnote (exceptions footnote) to the ''Effective Dates'' section honoring temporary exceptions from enforcement actions approved by the NERC Planning Committee before NERC proposed the Reliability Standard.

13. In Order No. 733, the Commission directed the ERO, under section 215(d)(5), to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities [16] and to remove the exceptions footnote from the ''Effective Dates'' section of the Reliability Standard.[17]

II. NERC Petition: Proposed Reliability Standard PRC–023–2 and Rule of Procedure, Section 1700—Challenges to Determinations

14. In a March 18, 2011 Filing (March 18 Petition), NERC requests Commission approval of Reliability Standard PRC–023–2 (Transmission Relay Loadability) and NERC Rules of Procedure Section 1700—Challenges to Determinations.

15. In support of the March 18 Petition, NERC states that the proposed Reliability Standard requires transmission owners, generator owners, and distribution providers to verify relay loadability using methods that achieve ''the reliability goal of this Standard in an effective and efficient manner familiar to the responsible entities.'' [18] In addition, NERC specifically identifies the benefits of proposed Reliability Standard PRC–023–2 as including (a) consistent identification of operationally critical circuits operated below 200 kV that must comply with the Requirements of the Standard, and (b) providing transmission operators, planning coordinators, reliability coordinators, and the ERO with more information regarding the criteria selected by entities for verifying relay loadability.[19]

A. Reliability Standard PRC–023–2

16. Reliability Standard PRC–023–2 contains six requirements with the stated purpose of ensuring that protective relay settings do not limit transmission loadability, do not interfere with system operators' ability to take remedial action to protect system reliability, and are set to reliably detect all fault conditions and protect the electrical network from these faults.[20] The proposed Reliability Standard also includes two attachments. Attachment A specifies the protection systems that are subject to and excluded from the Standard's Requirements. Attachment B specifies the criteria for determining the circuits which must comply with Requirements R1 through R5.

Requirement R1

17. NERC describes Reliability Standard PRC–023–2 Requirement R1 as follows:

> Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the identified criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the [bulk electric system] for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and power factor angle of 30 degrees[.] [21]

18. With the exception of clarifying language and the addition of criterion 10.1, proposed Requirement R1 retains the same criteria as currently existing PRC–023–1. Criteria 1 through 13 prescribe specific criteria to be used for certain transmission system configurations. These criteria account for the presence of devices such as series capacitors, and address circuit and transformer thermal capability.

19. Criterion 1 specifies transmission line relay settings based on the highest seasonal facility rating using the 4-hour thermal rating of a transmission line, plus a design margin of 150 percent. Criterion 2 allows transmission line relays to be set so that they do not operate at or below 115 percent of the highest seasonal 15-minute facility rating of a circuit, when a 15-minute rating has been calculated and published for use in real-time operations. Criterion 3 allows

[9] *Id.* P 60.

[10] *Id.* P 69.

[11] *Id.* P 237.

[12] *Id.* P 97.

[13] ''Out-of-step blocking'' refers to a protection system that is capable of distinguishing between a fault and a power swing. If a power swing is detected, the protection system, ''blocks,'' or prevents the tripping of its associated transmission facilities.

[14] Order No. 733 at 244.

[15] *Id.* P 264.

[16] *Id.* P 283.

[17] *Id.* P 284.

[18] March 18 Petition at 42.

[19] *Id.* at 5.

[20] Reliability Standard PRC–023–2, Section A.3 (Purpose).

[21] March 18 Petition at 30.

transmission line relays to be set so that they do not operate at or below 115 percent of the maximum theoretical power capability. Criterion 4 may be applied where series capacitors are used on long transmission lines to increase power transfer. Criterion 5 applies in cases where the maximum end-of-line three-phase fault current is small relative to the thermal loadability of the conductor. Criterion 6 may be used for system configurations where generation is remote from load busses or main transmission busses.

20. Criterion 7 is appropriate for system configurations that have load centers that are remote from the generation center. Criterion 8 applies to system configurations that have one or more transmission lines connecting a remote, net importing load center to the rest of the system. Criterion 9 applies to the same system configuration, but applies to the load end. Criterion 10 is specific to transmission transformer fault protective relays and transmission lines terminated only with a transformer. Criterion 11 may be used for transformer overload protection relays when criterion 10 cannot be met. Criterion 12 may be used when the circuits have three or more terminals. The limited circuit loading capability established by this criterion will become the facility rating of the circuit. Finally, criterion 13 is intended to apply when otherwise supportable situations and practical limitations are not identified under criteria 1 through 12.

21. NERC explains that Reliability Standard PRC–023–2 modifies PRC–023–1 by adding criterion 10.1 to address the Commission's directive that entities with protective relays set pursuant to Requirement R1.10 of PRC–023–1, which is criterion 10 of Requirement 1 of PRC–023–2, must verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with a fault.[22] The criterion requires coordination so that settings on a transformer's load responsive relay do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability.[23] NERC further states in the March 18 Petition that it believes Requirement 10.1 is equally effective and efficient as the approach directed in Order No. 733.[24]

Requirement R2

22. Proposed Reliability Standard PRC–023–2 adds a new Requirement R2 that requires each transmission owner, generation owner, and distribution provider to set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions modeled under Requirement R1. NERC states in the March 18 Petition that Requirement R2 has been added to proposed Reliability Standard PRC–023–2 to address the Commission's directive to include section 2 of PRC–023–1 Attachment A as an additional Requirement with the appropriate violation risk factor and violation severity level.[25] NERC has assigned this proposed Requirement a high violation risk factor and a severe violation severity level reflecting the impact to reliability of violating the Requirement.

Requirements R3, R4, and R5

23. Requirement R3 in Reliability Standard PRC–023–2 renumbers and makes conforming edits to Requirement R2 from PRC–023–1. Requirement R4 requires an entity that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide its planning coordinator, transmission operator, and reliability coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year. Similarly, Reliability Standard PRC–023–2 adds a new Requirement R5 that requires entities that set transmission line relays according to Requirement R1 criterion 12 to provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, to allow the ERO to compile a list of all circuits that have protective relays settings that limit circuit capability. In the March 18 Petition, NERC states that new Requirements R4 and R5, respectively, address the Commission's directives relating to providing transmission operators a list of transmission facilities that implement criterion 2 and directing that the ERO create a list of those facilities that have protective relays set pursuant to criterion 12.[26]

Requirement R6

24. Requirement R6 of Reliability Standard PRC–023–2 requires each planning coordinator to conduct an assessment at least once each calendar year (but no less frequently than every 15 months) by applying the criteria in Attachment B to determine the circuits in its planning coordinator area for which entities must comply with Requirements R1 through R5. Sub-part 6.1 requires the planning coordinator to maintain a list of circuits subject to PRC–023–2 per application of Attachment B identifying the year in which any criterion in Attachment B applies. Sub-part 6.2 requires the planning coordinator to provide the list to all Regional Entities, reliability coordinators, transmission owners, generators owners, and distribution providers within its planning coordinator area within 30 calendar days of establishing the initial list, and 30 days of any subsequent change thereto. NERC states in the March 18 Petition that the proposed sub-part 6.2, formerly Requirement R3.3 in PRC–023–1, modifies the Requirement in order to address the Commission's directive to add the Regional Entity to the list of entities that receive the list of critical facilities.[27]

Attachment A

25. Attachment A to Reliability Standard PRC–023–2 includes a new section 1.6 that extends the Standard's applicability to include phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of inadvertent tripping for loss of communications, even if there is no fault on the line. In addition, conforming changes are made to proposed section 2.1, formerly section 3.1 of the PRC–023–1, to recognize that elements described in new section 1.6 are no longer excluded from the proposed Standard's scope. NERC states in the March 18 Petition that these changes have been made to address the Commission's directives to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.[28] NERC further states that it believes section 1.6 of Attachment A is equally effective and efficient in addressing the Commission's concern as the approach directed in Order No. 733.[29]

[22] *Id.* at 20.

[23] The mechanical withstand capability is determined on the basis of the transformer's design and the periodic transformer maintenance to preserve that capability by the owner. The withstand capability could be compromised, for example, if the moisture level in a transformer is allowed to increase above the design value but remains within dielectric acceptance.

[24] March 18 Petition at 20–21.

[25] *Id.* at 24.

[26] *Id.* at 20, 23.

[27] *Id.* at 24.

[28] *Id.* at 25.

[29] *Id.*

Attachment B

26. Attachment B of Reliability Standard PRC–023–2 specifies six criteria that planning coordinators must apply to identify sub-200kV facilities that are subject to compliance with the Reliability Standard. Specifically, a facility is subject to PRC–023–2 if the facility meets any one of the following six criteria:

- Is a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the Quebec Interconnection, that has been included to address reliability concerns for loading of that circuit (Criteria B1);
- Is a monitored facility of an interconnection reliability operating limit, where the limit was determined in the planning horizon pursuant to Reliability Standard FAC–010 (System Operating Limits Methodology for Planning Horizon) (Criteria B2);
- Forms a path to supply off-site power to a nuclear plant as established in the nuclear plant interface requirements pursuant to Reliability Standard NUC–001 (Nuclear Plant Interface Coordination) (Criteria B3).[30]
- Is identified through a sequence of power flow analyses specified in Attachment B and performed by the planning coordinator (Criteria B4);
- Is selected by the planning coordinator based on technical studies or assessments other than those specified above, in consultation with the facility owner (Criteria B5); or
- Is mutually agreed upon for inclusion by the planning coordinator and the facility owner (Criteria B6).

27. NERC states in the March 18 Petition that while the six criteria presented in Attachment B vary from some of the guidance provided in Order No. 733, they nonetheless identify all facilities that must be subject to proposed Reliability Standard PRC–023–2 in order to achieve the Standard's reliability objective.[31] NERC further reports that it is in the process of applying the test to a representative sample of utilities from each of the three Interconnections and plans to file the results of these tests by February 17, 2013. NERC states that it plans to revise Attachment B, if necessary, pending the results of this test and clarifications made in Order No. 733–A.[32]

28. The Commission, in Order No. 733, provided guidance that a test to determine critical sub-200 kV facilities should include the same simulations and assessments as the Transmission Planning (TPL) Reliability Standards.[33] While the TPL Standards permit manual system adjustments between two contingencies, NERC explains in the March 18 Petition that it believes it is more informative, and in line with the reliability objective, to require testing of double contingencies without such manual adjustments, thereby modeling a situation in which an operator fails to, or does not have time to, make appropriate system adjustments. This focused testing exceeds the requirements of the TPL Standards and, NERC asserts, is an equally efficient and effective approach to addressing the Commission's concern that the test must be sufficiently robust to provide assurance that all appropriate facilities are identified and made subject to the Reliability Standard for the Standard to achieve its purpose.

29. In Order No. 733, the Commission also provided guidance regarding elements of a definition of desirable system performance that must inform any test to determine which sub-200 kV circuits are critical to system reliability. The Commission's guidance stated, among other things, that the power system should maintain all facilities within their applicable thermal (i.e., current), voltage, or stability ratings (short time ratings are applicable).[34] In the March 18 Petition, NERC asserts that it is most appropriate to focus on avoiding thermal loading of transmission circuits.[35] In order to achieve its reliability goal, NERC believes, Reliability Standard PRC–023–2 must apply to circuits whose relays will be challenged by excessive thermal loading to the point that a relay hampers the system operator's ability to take remedial action. NERC believes this test is an equally effective and efficient approach to addressing the Commission's concern regarding the rigorousness of the test.[36]

Implementation Plan

30. In the March 18 Petition, NERC proposes staggered effective dates for Reliability Standard PRC–023–2, i.e., the mandatory compliance date after an allotted implementation period, for each of the Standard's requirements. The implementation plan provides 18 months for planning coordinators to apply the criteria in Attachment B and determine which sub-200 kV circuits must be subject to the Standard. Those entities responsible for compliance on circuits identified by a planning coordinator pursuant to Requirement R6 are provided until the first day of the first calendar quarter 39 months following notification to become compliant, or until the first day of the first calendar year in which any criterion in Attachment B applies if the planning coordinator indentifies the circuit in an assessment of a future year more than 39 months beyond the year in which the assessment is conducted.

Violation Risk Factors/Violation Severity Levels

31. NERC assigns Requirements R1, R2, and R6 a ''high'' violation risk factor, Requirement R3 a ''medium'' violation risk factor, and Requirements R4 and R5 a ''lower'' violation risk factor. NERC also proposes violation severity levels for each of the Requirements of Reliability Standard PRC–023–2.

B. NERC Rules of Procedure Section 1700—Challenges to Determinations

32. In addition to the Reliability Standard, NERC included in its petition new Rules of Procedure Section 1700—Challenges to Determinations, which provides a process for registered entities to challenge a planning coordinator's determination made under a Reliability Standard that a facility operated below 200 kV is subject to compliance with the standard. Pursuant to Rule 1702, a registered entity is encouraged, but not required, initially to meet with the planning coordinator to resolve any dispute. If the matter remains unresolved, the registered entity may challenge the determination with the appropriate Regional Entity. The registered entity may appeal the Regional Entity's decision to NERC, and the NERC Board of Trustees would appoint a panel to review the Regional

[30] As we stated previously, ''[w]e would expect that any [nuclear plant interface requirements] agreed to between a nuclear plant generator operator and transmission entity would include all facilities needed to transmit offsite power and auxiliary power to the nuclear facility. *Mandatory Reliability Standard for Nuclear Plant Interface Coordination,* 125 FERC ¶ 61,065, at P 51 (2008).

[31] March 18 Petition at 14.

[32] *Id.* at 13.

[33] Order No. 733 at P 80.

[34] *Id.* P 84.

[35] March 18 Petition at 19. With respect to NERC's assertion, the Commission agrees that avoiding thermal loading may be appropriate criteria for some regions. However, for other regions, such as the Western Interconnection, voltage and stability criteria considerations would be included as appropriate.

[36] As explained in the March 18 Petition, the system performance measure in this test is less rigorous than that required by TPL–003 (System Performance Following Loss of Two or More bulk electric system Elements) because it ignores voltage and stability ratings. NERC points out, however, that the contingency condition in Attachment B is more stringent than that in TPL–003, and the contingency and system performance measure were developed together in order to align with the reliability objective of the proposed Standard. March 18 Petition at 19.

Entity decision. The Board of Trustees has the authority, but not the duty, to review the matter upon the request of the planning coordinator or registered entity. The registered entity may appeal the final NERC decision to the applicable governmental authority, e.g., the Commission for appeals within the United States.

III. Notice of Proposed Rulemaking and Comments

33. On September 15, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve Reliability Standard PRC–023–2.[37] In the NOPR, the Commission proposed to approve Reliability Standard PRC–023–2. The Commission indicated that the Version 2 standard and new Rule of Procedure 1700 adequately address the directed modifications set forth in Order No. 733. The Commission also proposed to accept the Attachment B criteria for identifying sub-200 kV facilities to which the Reliability Standard applies.[38] Finally, the Commission proposed to approve the implementation plan, Violation Risk Factors, and Violation Severity levels.

34. In addition, the NOPR set forth certain questions regarding the Attachment B criteria.[39] Specifically, the Commission proposed the following questions to be addressed in the report regarding the application of Attachment B criteria NERC intends to file by February 17, 2013:

- Whether the power system assessment proposed in criterion B4 includes the critical system conditions utilized under Reliability Standard TPL–003–0 Requirement R1.3.2;[40]
- Whether applicable entities evaluate relay loadability under the B4 criterion consistent with Requirement R1 which requires, in part, that they ''evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees'' in addition to applicable current data;[41]
- What ''technical studies or assessments'' will be used by planning coordinators to identify critical facilities under Criterion B5;[42] and
- Whether Attachment B is sufficiently comprehensive to capture all circuits in a planning coordinator's area that could have an operational impact on the reliability of the bulk electric system.[43]

35. On September 21, 2011, notice of the September 15 NOPR was published in the **Federal Register** with comments due on or before November 21, 2011.[44] Timely comments were filed by the American Public Power Association (APPA), ISO New England Inc. (ISO–NE), the Midwest Independent System Operator, Inc. (MISO), and NERC.

IV. Discussion

36. Pursuant to section 215(d)(2) of the FPA, the Commission approves Reliability Standard PRC–023–2, including the Violation Risk Factors and Violation Severity Levels, and implementation plan. The Reliability Standard meets the directives outlined in Order No. 733, and further contributes to the reliability of the Bulk-Power System by requiring load-responsive phase protection relay settings that will provide essential facility protection for faults while not limiting transmission loadability or interfering with system operators' ability to protect system reliability. In addition, the Reliability Standard provides for the consistent identification of operationally critical circuits operated below 200 kV that must comply with the Requirements of the Standard. Accordingly, we find that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

37. Also, pursuant to section 215(f) of the FPA, the Commission approves NERC Rule of Procedure Section 1700—Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA.[45] Rule of Procedure Section 1700 addresses the Order No. 733 directive for a mechanism by which a registered entity can challenge a determination by a planning coordinator made pursuant to Reliability Standard PRC–023–2.

38. NERC indicates in its comments that it is in the process of applying the test set forth in Attachment B of Reliability Standard PRC–023–2 to a representative sample of utilities from each of the three Interconnections and will file the results of these tests in a report on or before February 17, 2013. We adopt the NOPR proposal and direct NERC to address in the report several specific questions regarding the implementation of the applicability criteria set forth in Attachment B, as discussed below.

39. Further, commenters raise a number of concerns regarding the specific substantive Requirements of the Reliability Standard, the Standard's Attachment B, and the violation risk factor designations. These commenter concerns are discussed below.

A. Reliability Standard PRC–023–2

1. Requirement R1

40. Requirement 1 of PRC–023–2 provides that applicable entities must use one of the identified criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the [bulk electric system] for all fault conditions. Requirement R1.13 provides that ''[w]here other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.''

41. MISO contends that over-reliance on criterion R1.13 would adversely impact operations, reliability, flexibility, and transmission congestion costs, and lead to unnecessary transmission expansion in the future to comply with transmission planning standards. To avoid this result, MISO requests that the Commission clarify the applicability of the standard by narrowing the scope of the protection systems covered by the Standard under Attachment A. In particular, MISO requests the Commission clarify that the following protection systems are excluded from the standard: (a) Differential current relays and negative sequence relays; (b) supervisory elements with unanimous consent logic; (c) redundant voting protective relay schemes; and (d) switch-on-to-fault protective relay schemes. We address MISO's request below.

a. Differential Current Relays & Negative Sequence Relays

42. MISO requests that we clarify that differential current relay elements and negative sequence relay elements should not be covered by the standard ''as they would not trip with or without time delay on load current.''[46] MISO argues that the exclusion of these

[37] *Transmission Relay Loadability Reliability Standard,* 136 FERC ¶ 61,187 (September 15, 2011) (September 15 NOPR).

[38] *Id.* P 38.

[39] *Id.* PP 41–45.

[40] *Id.* P. 43.

[41] *Id.*

[42] *Id.* P 44.

[43] *Id.* P 45.

[44] 76 FR 58,424 (2011).

[45] Section 215(f) of the FPA provides, *inter alia,* that ''[a] proposed rule or proposed rule change shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest and satisfies the requirements of subsection (c).''

[46] MISO Comments at 3.

specific relay elements from the proposed standard ''would be consistent with the purpose and intent of the standard and would prevent an inappropriate and unnecessary expansion of the standard's applicability.'' [47]

43. We grant MISO's request for clarification in part. As noted by MISO, differential current relay elements and negative sequence relay elements, by their nature, are not load responsive. As the Commission noted previously, the exclusion of a protection system from Reliability Standard PRC–023 appears to be unnecessary if the system is not load-responsive.[48] Therefore, we grant MISO's request for clarification to the extent that non-load responsive relays are not covered by Reliability Standard PRC–023–2, however we decline to direct NERC to include the assets in the exclusion list of Section 3 of Attachment A as the exclusion list should be limited to protection systems that would otherwise be subject to the Standard.

b. Supervisory Relay Elements

44. In Order No. 733, the Commission directed NERC to include supervisory relay elements on the list of relays and protection systems that are specifically subject to the PRC–023 Reliability Standard.[49] In Order No. 733–B, the Commission clarified that its directive regarding the applicability of the Reliability Standard to supervisory relays does not foreclose the development of an approach tailored to eliminate application of the standard to some supervisory relays but not to others, where technically justified.[50]

45. In response to the directive, NERC modified Attachment A of Reliability Standard PRC–023–2, which identifies types of protection systems that are subject to, and others that are excluded from, the standard. In part, Attachment A provides that ''this standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to * * * 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes * * * where the scheme is capable of tripping for loss of communications.'' In the March 18 Petition, NERC explained that section 1.6, while addressing a subset of supervisory relays, is equally effective and efficient in addressing the Commission's reliability concern. According to NERC, including all supervisory relays would have unintended negative impacts on system reliability by impacting the dependability and security of certain protection systems.[51] NERC explains that supervisory overcurrent elements used as fault detectors ''by themselves cannot trip on load current, with or without time delay. Since the trip logic requires assertion of the fault detector and the supervised protective function (which already is required to meet the loadability requirements), the overall protective function will meet the loadability requirement.'' [52]

Comments

46. In its comments, MISO raises a concern that an interpretation of the term ''phase overcurrent supervisory elements'' in section 1.6 of Attachment A that includes elements in a unanimous consent scheme could lead to unnecessary facility limit reductions.[53] MISO asks the Commission to clarify that it is acceptable to consider ''unanimous consent'' logic when evaluating transmission relay loadability. According to MISO, ''[i]f a relay scheme contains multiple relay elements and requires 'unanimous consent' among two or more of the relay elements in order to initiate a tripping action [of a circuit breaker], transmission relay loadability should be based solely on the relay element that is least sensitive to load so long as the relay elements could never initiate a tripping action without the operation of the relay element least sensitive to load.'' [54]

Commission Determination

47. Giving due weight to NERC's technical expertise on this issue, we approve NERC's modification to Attachment A and find that NERC has developed an equally efficient and effective approach to addressing the Order No. 733 directive regarding supervisory relays. NERC's proposal identifies a subset of supervisory relay elements, consistent with the Commission's clarification in Order No. 733–B.

48. We deny MISO's request for clarification. There are various types of protection schemes. MISO describes a specific protection scheme that uses unanimous consent logic and asks whether elements of the scheme are subject to Reliability Standard PRC–023–2. This is a fact intensive inquiry, and we will not rule on this matter based on the information provided in MISO's comments. If MISO seeks further clarification of this issue, it should pursue the matter with NERC. The Commission will not make a determination on MISO's specific scenario without a complete record and without it going through NERC's Reliability Standards development process or interpretation process.

c. Redundant Voting Schemes—the Most Load Sensitive Relay

49. MISO requests that we clarify how entities should handle certain redundant voting protective relay schemes.[55] MISO explains that, in a redundant voting protective relay scheme for a transmission facility, there are three protective relay schemes and only two of the three must operate to initiate tripping. MISO argues that the most load sensitive of these three relay schemes should be exempt from the standard, ''so long as the most load sensitive of the three protective relay scheme can never initiate a tripping action on its own with[out] a tripping output from one of the other two protective relay schemes.'' [56]

50. We decline to grant MISO's request on this issue. MISO's limited comments on this issue do not provide adequate information or technical support for its request. Without adequate support, the Commission cannot respond to MISO's request.

d. Switch-on-to-Fault Protective Relay Schemes

51. MISO requests that the Commission clarify that a switch-on-to-fault protective relay scheme, which is specifically included in section 1.3 of Attachment A, may be excluded from the requirements of the Reliability Standard if it meets each of three stated conditions presented by MISO.[57]

52. Currently effective Reliability Standard PRC–023 explicitly addresses switch-on-to-fault protective relay schemes. Switch-on-to-fault schemes are protection systems designed to trip a transmission line breaker when the breaker is closed into a fault. Because the current fault detectors for these systems must be set low enough to detect ''zero-voltage'' faults, i.e., close-in, three-phase faults, these systems may be susceptible to operate on load.[58] We note that the System Protection and Control Task Force acknowledged, with

[47] *Id.*

[48] *Transmission Relay Loadability Reliability Standard,* 127 FERC ¶ 61,175, at n. 98 (2009).

[49] Order No. 733 at P 264.

[50] Order No. 733–B at P 39.

[51] March 18 Petition at 25–28.

[52] *Id.* at 27.

[53] MISO Comments at 4.

[54] *Id.*

[55] MISO Comments at 5.

[56] *Id.*

[57] *Id.* at 5–6.

[58] Order No. 733 at n. 187.

regard to switch-on-to-fault schemes ''* * * a concern, based on actual events which have occurred in connection with blackouts, for the undesired operation of [switch-on-to-fault] schemes when a breaker is closed into a line.'' [59] Because the relays applied in switch-on-to-fault schemes are load-responsive, the Commission agreed with the ERO's technical decision to make such relays subject to the requirements of PRC–023. As noted above, MISO proposed a set of conditions that would remove an otherwise load-responsive relay from the requirements of Reliability Standard PRC–023. MISO has not, however, provided any explanation or technical support for its proposed conditions. Therefore, we decline to grant the requested clarification.

2. Requirement R3

53. Requirement R3 of PRC–023–2 requires a transmission owner, generator owner and/or distribution provider to obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator for a calculated circuit capacity with the practical limitations described in Requirement R1, criteria 6, 7, 8, 9, 12, or 13.

a. Comments

54. MISO requests that the Commission clarify that Requirement R3 was not intended to create an obligation of the planning coordinator, transmission operator and reliability coordinator to independently verify or approve the calculated circuit capability provided by the transmission owner, generation owner or distribution provider.[60] MISO argues that this obligation to obtain the agreement could impute an obligation on the planning coordinator, transmission operator and/or reliability coordinator to evaluate the calculated circuit capability without providing corresponding criteria that should be applied in the evaluation.[61] MISO also requests that the Commission provide guidance on how such entities should resolve disputes over calculated circuit capabilities.

b. Commission Determination

55. We deny MISO's request for clarification. The Commission addressed MISO's concern in Order No. 733.[62] Specifically, in the Order No. 733 rulemaking, commenters argued that the use of the term ''agreement'' in PRC–023–1 simply meant that ''the entity calculating the circuit capability is required to provide the circuit capability to the relevant functional entities'' and that ''planning coordinators, transmission operators, and reliability coordinators must simply agree that they will use the circuit capability provided by the transmission owner, generator owner, or distribution owner.'' [63] The concerns raised at that time mirror the concerns raised by MISO; commenters indicated that the applicable parties did not want to be ''responsible for reviewing and approving the calculated circuit capabilities under Requirement R[3].'' [64]

56. The Commission rejected the commenters' arguments in Order No. 733, finding that the language ''shall obtain the agreement'' requires that ''the entity calculating the circuit capability must reach an understanding with the relevant functional entity that the calculated circuit capability is capable of achieving the reliability goal of PRC–023–1.'' [65] In addition, the Commission clarified that since the Standard is ''intended to ensure that protective relay settings do not limit transmission loadability or interfere with system operators' ability to take remedial action to protect system reliability, and to ensure that relays reliably detect all fault conditions and protect the electrical network from these faults,'' the agreement required under Requirement R3 should ''center around achieving these purposes.'' [66] Having adequately addressed this matter in Order No. 733, it is unnecessary to elaborate further in response to MISO and, accordingly, we deny MISO's request on this issue.

57. Further, to the extent that a dispute arises between responsible entities over the determination of a calculated circuit capability under Requirement R3, nothing precludes the responsible entities from raising the dispute with the applicable Regional Entity.

3. Requirement R6

58. Requirement R6 of the Reliability Standard requires planning coordinators to conduct an assessment applying the criteria in Attachment B to determine a list of circuits subject to PRC–023–2 Requirements R1 through R5. Under Attachment B, the planning coordinator is required to evaluate ''[t]ransmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the [bulk electric system].''

a. Comments

59. MISO requests clarification regarding the application of Requirement R6 to sub-100 kV facilities.[67] Specifically, MISO requests clarification ''with regard to what final and FERC-approved process is used by the Regional Entities to identify sub-100 kV facilities 'critical to the reliability of the bulk electric system.' '' [68] MISO further requests clarification on how planning coordinators will be provided access to the list of such sub-100 kV facilities, and, finally, MISO requests clarification whether the use of such a list of sub-100 kV facilities is adequate to demonstrate compliance with Requirement R6.

b. Commission Determination

60. With regard to MISO's request concerning the identification of sub-100 kV facilities, we note that bulk electric system facilities are currently identified through the application of NERC's definition of bulk electric system and NERC's registration process, as applied by the Regional Entities.[69] Regional Entities should inform planning coordinators of such sub-100kV facilities that already may have been identified so that the planning coordinator is able to fulfill its responsibilities pursuant to Requirement R6.

61. We deny MISO's request for clarification ''that the use of such a list as/if provided by the Regional Entities is adequate to demonstrate compliance with a requirement to evaluate 'Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the [bulk electric system].' ''[70] The identification of facilities is only the first step in the process of determining whether the Standard applies. Once a planning coordinator has been provided with a list of sub-100 kV facilities that are part of the bulk electric system, if any, it must apply the criteria in Attachment B to determine whether Requirements R1 through R5 of Reliability Standard PRC–023–2 will apply to the individual facilities.

4. Attachment B

62. Attachment B specifies which circuits must comply with

[59] NERC Planning Committee, System Protection and Control Task Force, ''Switch-on-to-Fault Schemes in the Context of Line Relay Loadability,'' at 2 (June 7, 2006).

[60] *Id.* at 6–7.

[61] *Id.*

[62] Order No. 733 at P 229.

[63] *Id.* P 228.

[64] *Id.*

[65] *Id.* P 229.

[66] *Id.*

[67] MISO Comments at 8.

[68] *Id.*

[69] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693 FERC Stats. & Regs. ¶ 31,242, at P 77 (2007).

[70] MISO Comments at 8.

Requirements R1 through R5. Criterion B4 addresses circuits that are identified through a specified sequence of power flow analyses performed by the planning coordinator, which simulate double contingencies without manual adjustments between the contingencies.

a. Comments

63. IS0–NE requests that the Commission direct the ERO to remove criterion B4 of Attachment B from PRC–023–2.[71] ISO–NE argues: (1) That such a criterion does not accurately recognize how the bulk electric system is operated; (2) that the system is neither planned nor operated to withstand two overlapping outages without intervening operator action; and (3) that such testing may result in unsolved cases, or voltages well below criteria.[72] As an example, ISO–NE cites a system designed to bring on fast start generation before the second contingency. ISO–NE argues that testing under that scenario without the fast start generation removes transmission paths into an area, thus increasing current flows on the remaining circuits and increasing reactive losses, resulting in lower voltages. In addition, ISO–NE states that unsolved cases have no flows to evaluate and therefore cannot be analyzed as required under criterion B4, and that solved cases with below-criteria voltage and excessive currents are unrealistic. ISO–NE concludes that such simulations may misidentify system conditions as severe cases when in reality they are not, thwarting the purpose of the testing.

64. ISO–NE also asserts that criterion B4 provides no guidance on how the planning coordinator should dispatch the system in a model that tests overlapping contingencies, potentially resulting in different base assumptions used by the various planning coordinators.

b. Commission Determination

65. The Commission recognizes that concerns exist regarding the application of Attachment B. As discussed below, NERC will be providing a summary of the base cases used in applying the Attachment B criteria and an assessment of how the base cases used for the analysis relate to TPL–003–0, Requirement R1.3.2 in response to our Order No. 733 directive. In the NOPR, the Commission expressed concern that criterion B4 of Attachment B is silent as to the rigor of the simulations other than requiring planning coordinators to use their engineering judgment.[73] NERC's additional information regarding the base cases used in applying the Attachment B criteria will allow the Commission and other interested parties to evaluate whether further modifications to Attachment B may be warranted. Accordingly, we deny ISO–NE's request on this issue and will not direct the ERO to develop modifications to Attachment B at this time.

66. Therefore, we decline to direct NERC to remove criterion B4 from PRC–023–2 at this time.

5. Violation Risk Factors/Violation Severity Levels

67. As noted above, NERC has proposed a ''high'' violation risk factor for Requirement R6 of Reliability Standard PRC–023–2.

a. Comments

68. MISO requests that the Commission reject the assignment of a high violation risk factor to Requirement 6, arguing: (1) That a high violation risk factor implies there is a direct correlation between instability, uncontrolled separation and cascading outages and the maintenance of a list of sub-200 kV circuits to which the planning coordinator believes the requirements of the standard applies; (2) that there is no such direct correlation, as evidenced by the fact that NERC has created and the Commission is proposing to accept a process by which entities can dispute the inclusion of circuits on the planning coordinator's list; and (3) that appearance on or absence from the list in itself will not cause or prevent instability, uncontrolled separation and cascading outages; some other event or Reliability Standards violation (i.e., operating above System Operating Limits) would have to occur to trigger any impact to reliability.[74]

b. Commission Determination

69. In Order No. 733, we directed NERC to assign a ''high'' violation risk factor to Requirement R3 of Reliability Standard PRC–023–1.[75] The Requirement at issue is renumbered Requirement R6 in Reliability Standard PRC–023–2. NERC's assignment of a ''high'' violation risk factor to Requirement R6 is therefore consistent with our prior directive.

70. MISO's request is an untimely argument against an explicit directive from Order No. 733. Therefore, we reject MISO's request for a rejection of the assignment of a ''high'' violation risk factor to Requirement R6.

6. NERC Report on Implementation of Attachment B

71. In Order No. 733, the Commission directed NERC to specify the test that planning coordinators will use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.[76] In addition, the Commission directed NERC to file both the test and the results of applying the test to a representative sample of utilities from each of the three interconnections.[77] Attachment B to Reliability Standard PRC–023–2 represents the test filed in response to the above described directive. The NOPR set forth questions intended to assist the Commission's understanding regarding the implementation of the test. Specifically, the Commission proposed that NERC address the following questions regarding the application of Attachment B criteria in the report:

- Whether the power system assessment proposed in criterion B4 includes the critical system conditions utilized under Reliability Standard TPL–003–0 Requirement R1.3.2;[78]
- Whether applicable entities evaluate relay loadability under the B4 criterion consistent with Requirement R1 which requires, in part, that they ''evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees'' in addition to applicable current data;[79]
- What ''technical studies or assessments'' will be used by planning coordinators to identify critical facilities under criterion B5;[80] and
- Whether Attachment B is sufficiently comprehensive to capture all circuits in a planning coordinator's area that could have an operational impact on the reliability of the bulk electric system.[81]

a. Comments

72. In its November 21, 2011 Comments, NERC, with APPA concurring, responds to the questions proposed for inclusion in the report NERC intends to file by February 17, 2013.

73. With regard to the question whether the power system assessment proposed in criterion B4 includes the critical system conditions utilized under

[71] ISO–NE Comments at 4.

[72] *Id.* at 2–3.

[73] September 15 NOPR at P 43.

[74] MISO Comments at 7–8.

[75] Order No. 733 at P 297.

[76] *Id.* P 69.

[77] *Id.*

[78] *Id.* P 43.

[79] *Id.*

[80] *Id.* P 44.

[81] *Id.* P 45.

Reliability Standard TPL–003–0, Requirement R1.3.2, NERC states that the goal of the power flow analysis is to have planning coordinators utilize the base cases that are used for demonstrating compliance with the TPL Reliability Standards.[82] NERC proposes to include in its report a summary of the base cases used in applying the Attachment B criteria and an assessment of how the base cases used for the analysis relate to TPL–003–0, Requirement R1.3.2.[83]

74. In response to the proposed question whether applicable entities evaluate relay loadability under the B4 criterion consistent with Requirement R1 which requires, in part, that they ''evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees'' in addition to applicable current data, NERC states that, although the measures in criterion B4 of Attachment B do not explicitly reference voltage and power factor, the measures were derived from Requirement R1 of PRC–023–2; specifically, 0.85 per unit voltage and 30 degree power factor angle.[84] NERC states, therefore, that it is not necessary for it to include in the report a comparison of the results obtained using criterion B4 to the results that would be achieved based on assumptions consistent with Requirement R1.

75. Regarding the question proposed in the NOPR concerning what ''technical studies or assessments'' will be used by planning coordinators to identify facilities under criterion B5, NERC states that Attachment B does not identify a specific list to avoid unnecessarily limiting the technical studies or assessments a planning coordinator may use to identify circuits.[85] NERC proposes to include a discussion in the report on the types of studies that planning coordinators may use.[86]

76. Finally, in response to the last proposed question of whether Attachment B is sufficiently comprehensive to capture all circuits in a planning coordinator's area that could have an operational impact on the reliability of the bulk electric system, NERC proposes to include in the report an assessment that demonstrates whether Attachment B is comprehensive enough to capture all circuits that could have an operational impact on the reliability of the bulk electric system in the context of transmission relay loadabilty.[87]

b. Commission Determination

77. As discussed above, NERC reports that it is in the process of applying the test set forth in Attachment B to a representative sample of utilities from each of the three Interconnections and will file the results of these tests in a report on or before February, 2013. In light of the discussion in NERC's November 21 Comments,[88] we accept NERC's proposed plan to respond to the following three questions and direct NERC to include in the report:

- A summary of the base cases used in applying the Attachment B criteria and an assessment of how the base cases used for the analysis relate to TPL–003–0, Requirement R1.3.2;
- A discussion of the types of studies that planning coordinators may use to identify circuits under Attachment B; and
- An assessment that demonstrates whether Attachment B is comprehensive enough to capture all circuits that could have an operational impact on the reliability of the bulk electric system in the context of transmission relay loadabilty.

78. However, we are not persuaded by NERC's statement that it is not necessary for NERC to include in the report a comparison of the results obtained using criterion B4 to the results that would be achieved based on assumptions consistent with Requirement R1. The 0.85 per unit and 30 degrees power factor criteria in Requirement R1 is based on system conditions, voltage, current, and angle, observed prior to the cascading stage of the blackout. Although NERC states that criterion B4 was derived from these system criteria,[89] the Commission is concerned that testing, which does not, at a minimum, compare whether criteria that do not consider voltage or angle affect the appropriate identification of applicable facilities, is not responsive to ensuring the reliability objective of the critical facilities test or the reliability objective of PRC–023. For these reasons, we direct NERC to evaluate, in the report, relay loadability under the B4 criterion consistent with Requirement R1, which requires, in part, that NERC ''evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees'' in addition to applicable current data.

B. NERC Rules of Procedure Section 1700—Challenges to Determinations

1. NERC Petition

79. In its petition, NERC submitted new Rules of Procedure Section 1700—Challenges to Determinations, which sets out the procedure for a registered entity to challenge a determination by a planning coordinator under Reliability Standard PRC–023–2.

2. NOPR

80. In the NOPR, we proposed to approve NERC Rules of Procedure Section 1700, specifically proposed Rule 1702, finding that it addresses the Order No. 733 directives that NERC establish a mechanism for registered entities to challenge criticality determinations made by a planning coordinator.

3. Comments

81. No comments were filed concerning proposed Rules of Procedure Section 1700—Challenges to Determinations.

4. Commission Determination

82. NERC's proposal is responsive to the Commission's directive in Order No. 733. Accordingly, we adopt our NOPR proposal and we approve, pursuant to section 215(f) of the FPA, NERC Rule of Procedure Section 1700—Challenges to Determinations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and satisfying the requirements of section 215(c) of the FPA.

V. Information Collection Statement

83. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[90] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA)[91] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[92]

84. The Commission is submitting these reporting and recordkeeping

[82] NERC Comments at 3.
[83] *Id.*
[84] *Id.*
[85] *Id.* at 4–5.
[86] *Id.* at 5.
[87] *Id.*
[88] *Id.* at 12–19.
[89] *Id.* at 3.
[90] 5 CFR 1320.11.
[91] 44 U.S.C. 3501–20.
[92] 44 U.S.C. 3502(A)(3)(i), 44 U.S.C. 3507(a)(3).

requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

85. This Final Rule approves Reliability Standard PRC–023–2 (Transmission Relay Loadability) which replaces currently effective Reliability Standard PRC–023–1 approved by the Commission in Order No. 733. Rather than creating entirely new requirements regarding the setting of protective relays, the revised Reliability Standard instead modifies and improves the existing Reliability Standard. Thus this Final Rule does not impose entirely new burdens on the effected entities. For example, the currently effective Reliability Standard PRC–023–1 requires transmission owners, generation owners, and distribution providers to each have evidence to show that each of its transmission relays are set according to one of the criteria in criteria R1.1 through R1.13. Similarly, revised Reliability Standard PRC–023–2 requires transmission owners, generation owners, and distribution providers to have evidence that each of its transmission relays is set according to one of the 13 criteria in Requirement R1 but adds that each such entity shall also have evidence that relays set according to criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the Standard. Thus, the recordkeeping obligations for some Requirements are more specific but not necessarily more expansive than those of currently effective Reliability Standard PRC–023–1. However, revised PRC–023–2 does add new Requirements, each of which has new recordkeeping obligations.

86. Requirement R2 requires each transmission owner, generator owner, and distribution provider to have evidence that its out-of-step blocking elements are set in accordance with the Standard, and Requirements R4 and R5 require those same entities to maintain evidence that they have informed the appropriate parties of their updated lists of certain circuits. Under Requirement R6, planning coordinators are required to execute a test for applicability of the Standard as set forth in Attachment B and retain analyses, calculation summaries, or study reports to evidence execution of the test, whereas under the currently effective PRC–023–1, a test was required but only the results needed to be retained. Because an unspecified test is currently required to be carried out on facilities operated at between 100 kV and 200 kV under currently effective Reliability Standard PRC–023–1, for purposes of this analysis, we assume that there is little additional cost for planning coordinators to implement and document that portion of the test. However, the Requirement R6 of the revised Standard imposes the new burdens of performing the test on sub-100 kV facilities, maintaining appropriate records, and distributing the list of circuits identified by the test to Regional Entities.

87. *Public Reporting Burden:* Our estimate below regarding the number of respondents is based on the NERC compliance registry as of January 26, 2012. According to the NERC compliance registry, there are 337 transmission owners, 858 generation owners, 554 distribution providers, and 81 planning coordinators. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of entities responding will be approximately 660 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a distribution owner, and 81 planning coordinators.[93] The estimated burden for the requirements in this Order follow:

Changes to FERC–725G data collection	Number of respondents annually (1)	Number of responses per respondent (2)	Average burden hours per response[94] (3)		Total annual hours (1 × 2 × 3)
R1 criterion 1.10: TOs, GOs, and DPs must analyze and document criterion 1.10 compliance.	660	1	*Analysis for compliance documents.*	8	5,280
	.....	.....	*Record Retention*	2	1,320
R2: TOs, GOs, and DPs must perform analysis and retain evidence of compliance.	660	1	*Analysis for compliance documents.*	8	5,280
	.....	.....	*Record Retention*	2	1,320
R4 and R5: TOs, GOs, and DPs must distribute updated lists and retain evidence that lists were distributed.	660	1	*Reporting (dist. of list)* ..	10	6,600
	.....	.....	*Record Retention*	10	6,600
R6: PC must perform assessment, distribute list of circuits and retain evidence of testing and distribution[95].	81	1	*Reporting (assessment and dist. of list).*	20	1,620
	.....	.....	*Record Retention*	10	810
Total	.....	.....	.....	.....	28,830

[93] Under its applicability provisions, proposed Reliability Standard applies to specified circuits such that very few, if any, generator owners that are not also a transmission owner and/or a distribution provider will be subject to the Standard.

[94] The burden hours are based on estimates that the Commission has used for similar reporting requirements.

[95] This applies to the portion of R6 that deals with testing for sub-100 kV facilities as described in the text. In addition it includes burden hours associated with adding Regional Entities to the list of entities to receive a list of circuits from the planning coordinator.

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements and recordkeeping burden associated with Reliability Standard PRC–023–2.

- *Total Annual Hours for Collection:* (Reporting and Record Retention) = 28,830 hours.
- *Total Estimated Reporting/Analysis Cost* = 18,780 hours @ $120/hour = $2,253,600.
- *Total Estimated Record Retention Cost* = 10,050 hours @ $28/hour = $281,400.
- *Total Estimated Annual Cost (Reporting + Record Retention)*[96] = $2,535,000.
- *Title:* Mandatory Reliability Standards for the Bulk-Power System
- *Action:* FERC 725G, Proposed Modification to FERC–725G.
- *OMB Control No:* 1902–0252.
- *Respondents:* Business or other for profit, and/or not for profit institutions.
- *Frequency of Responses:* On occasion.
- *Necessity of the Information:* This Final Rule approves a revised Reliability Standard that modifies an existing requirement regarding setting protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. Reliability Standard PRC–023–2 requires entities to set transmission relays according to specified criteria and to retain evidence of compliance. It also requires planning coordinators to implement a test to determine which sub-200 kV facilities are critical to the reliability of the power system and subjects such facilities to the requirements of the Standard. The revised Reliability Standard requires entities to maintain records subject to review by the Commission and NERC to ensure compliance with the Reliability Standard.
- *Internal review:* The Commission has reviewed the requirements pertaining to the revised Reliability Standard for the Bulk-Power System and determined that the requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific objective support for the burden estimates associated with the information requirements.

88. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gove*, Phone: (202) 502–8663, fax: (202) 273–0873]. Comments on the requirements of this order may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at *oira_submission@omb.eop.gov*. Please reference OMB Control Number 1902–0252 and the docket number of this Order in your submission.

VI. Environmental Analysis

89. 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.[97] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[98] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VII. Regulatory Flexibility Act Analysis

90. The Regulatory Flexibility Act of 1980 (RFA)[99] generally requires a description and analysis of proposed and 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 order and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[100] The SBA has established a size standard for electric utilities, stating that 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.[101]

91. Reliability Standard PRC–023–2 modifies currently existing Reliability Standard PRC–023–1 which requires applicable entities to set protective relays according to specific criteria, to communicate about such settings with specified entities, and to conduct assessments to determine the applicability of the Standard to 100–200 kV facilities. The revised Standard modifies PRC–023–1 by (1) increasing communication and documentation requirements, (2) extending the applicability of the Standard to formerly excluded relays, and (3) standardizing the terms of the assessment whose terms were formerly not specified. In addition, PRC–023–2 extends the current requirement that planning coordinators annually assess which 100–200 kV circuits must be brought into compliance with the Standard and will require planning coordinators to carry out the assessment with respect to some sub-100 kV facilities.

92. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA–861 indicates that perhaps as many as 108 transmission owners, 327 distribution providers, 52 generation owners, and 14 planning coordinators qualify as small entities. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The net number of registered entities that qualify as small entities responding to this rule will be approximately 339 entities registered as a transmission owner, a distribution provider, or a generation owner that is also a transmission owner and/or a distribution provider, and 8 planning coordinators. The Final Rule directly affects each of the small entities. Therefore, FERC has determined that this Final Rule will have an impact on a substantial number of small entities. However, the Commission has determined that the impact on entities affected by the Final Rule will not be significant. The Commission estimates that in order to comply with the Standard's modification of existing requirements each of the small entities registered as planning coordinators will face a cost of $2,680 and each of the remaining small entities (transmission owners, distribution providers, or generation

[96] The hourly reporting cost is based on the estimated cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

[97] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[98] 18 CFR 380.4(a)(5).

[99] 5 U.S.C. 601–612.

[100] 13 CFR 121.101.

[101] 13 CFR 121.201, Sector 22, Utilities & n.1.

owners that are also transmission owners and/or distribution providers) will face a cost of $3,512. Accordingly, the Commission determines that the incremental cost of Reliability Standard PRC–023–2 (going from PRC–023–1 to PRC–023–2) is minimal, and should not present a significant operating cost to any of the small entities.

93. Based on this understanding, the Commission certifies that this Reliability Standard will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VIII. Document Availability

94. 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.

95. 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.

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

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–6758 Filed 3–20–12; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[EPA–R09–OAR–2012–0189; FRL–9649–1]

Approval and Promulgation of Implementation Plans; Designation of Areas for Air Quality Planning Purposes; State of California; Ozone; Nitrogen Dioxide; Technical Amendments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; technical amendments.

SUMMARY: EPA is making technical amendments to the Code of Federal Regulations (CFR) to reflect the final actions published by the Agency on October 7, 2003, April 30, 2004, and May 5, 2010 in connection with the designations and classifications of certain areas in California for the 1971 annual nitrogen dioxide standard and the 1997 eight-hour ozone standard pursuant to the Clean Air Act. The areas that are the subject of these technical amendments include Riverside County, Western Mojave Desert, South Coast Air Basin, Eastern Kern County, and San Diego County.

DATES: These technical amendments are effective on March 21, 2012.

FOR FURTHER INFORMATION CONTACT: Doris Lo, EPA Region IX, (415) 972–3959, *lo.doris@epa.gov.*

SUPPLEMENTARY INFORMATION:

Technical Amendment for California—NO_2 Table in 40 CFR 81.305

In today's action, we are making a technical amendment to correct an erroneous codification of our 2003 boundary change rule with respect to the ''California—NO_2 (1971 Annual Standard)'' table in 40 CFR 81.305.[1] As described in our October 7, 2003 final rule (68 FR at 57821 and 57824) redesignating certain air quality planning area boundaries in southern California, we intended to revise the entry in the table for ''Riverside County (portion within SE. Desert AQMD) County'' to ''Riverside County (Coachella Valley planning area)'' and to revise the entry for ''Riverside County, non-AQMA portion County'' to ''Riverside County (portion not within South Coast Air Basin or Coachella Valley planning area).'' However, the entry for ''Riverside County (Coachella Valley planning area),'' which was to become an entry in the table, is not found in the current version of the ''California—NO_2 (1971 Annual Standard)'' table whereas the entry for ''Riverside County, non-AQMA portion County,'' which was intended to be replaced, remains in the table. In today's action, we are making a technical amendment to ensure that the ''California—NO_2 (1971 Annual Standard)'' table in 40 CFR 81.305 to accurately reflect the intent of our 2003 boundary change action.

Today's technical amendment makes no change to the substance of our October 7, 2003 final rule.

Technical Amendments for California—Ozone (8-Hour Standard) Table in 40 CFR 81.305

With respect to the ''California—Ozone (8-Hour Standard)'' table in 40 CFR 81.305, we are making a number of technical amendments that stem from previous EPA rulemakings. All of the subject areas are located within the State of California.

On April 30, 2004, at 69 FR 23858, we published a final rule announcing and promulgating designations, classifications, and boundaries for areas in the country with respect to the 1997 8-hour ozone National Ambient Air Quality Standard (NAAQS) in accordance with the requirements of the Clean Air Act (CAA). In our April 30, 2004 final rule, we designated the Western Mojave Desert area as a moderate nonattainment area for the 1997 8-hour ozone National Ambient Air Quality Standard. See 69 FR 23858, at 23884–85 (April 30, 2004). Subsequently, on May 5, 2010, EPA published a final rule granting California's request for reclassification of several areas for the 1997 8-hour ozone standard. See 75 FR 24409 (May 5, 2010). The Western Mojave Desert was not among the areas that were the subject of EPA's May 5, 2010 final rule, but the changes made to the ''California—Ozone (8-Hour Standard)'' table to codify our May 5, 2010 final rule had the inadvertent effect of removing a portion of the definition of the Western Mojave Desert 8-hour ozone nonattainment area from the ''California—Ozone (8-Hour Standard)'' table. In today's action, EPA is making a technical amendment to re-insert the inadvertently removed portion of the definition of the Western Mojave Desert area into the ''California—Ozone (8-Hour Standard)'' table in 40 CFR 81.305.

Second, in codifying the designations in EPA's April 30, 2004 final rule, we inadvertently indented the title of the

[1] The table heading was recently revised to read ''California—NO_2 (1971 Annual Standard)'' in a final rule published on February 17, 2012 at 77 FR 9532, at 9540, effective February 29, 2012. The table heading previously had been ''California-NO_2.''