standards, the entities with market-based rates which are affected by this Final Rule likely come under the following categories [117] with the indicated thresholds (in terms of number of employees [118]):

- Hydroelectric Power Generation, 500 employees.
- Fossil Fuel Electric Power Generation, 750 employees.
- Nuclear Electric Power Generation, 750 employees.
- Solar Electric Power Generation, 250 employees.
- Wind Electric Power Generation, 250 employees.
- Geothermal Electric Power Generation, 250 employees.
- Biomass Electric Power Generation, 250 employees.
- Other Electric Power Generation, 250 employees.

82. The categories for the applicable entities have a size threshold ranging from 250 employees to 750 employees. For the analysis in this Final Rule, we are using the threshold of 750 employees for all categories. We anticipate that a maximum of 82 percent of the entities potentially affected by this Final Rule are small. In addition, we expect that not all of those entities will be able to or will choose to offer primary frequency response service.

83. Based on the estimates above in the Information Collection section, we expect a one-time cost of $576 (including the burden cost related to filing both the tariff and the EQR) for each entity that decides to offer primary frequency response service.

84. The Commission does not consider the estimated cost per small entity to impose a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VII. Document Availability

85. 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 the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

[117] 13 CFR 121.201, Sector 22, Utilities.

[118] SBA's regulations at 13 CFR 121.201 state that "[t]he number of employees . . . indicates the maximum allowed for a concern and its affiliates to be considered small."

86. From the Commission'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.

87. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's 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.*

VIII. Effective Date and Congressional Notification

88. The Final Rule is effective February 25, 2016. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

List of Subjects in 18 CFR Part 35

Electric power rates; Electric utilities; Reporting and recordkeeping requirements.

By the Commission.

Issued: November 20, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. In § 35.37, revise paragraph (c)(1) to read as follows:

§ 35.37 Market power analysis required.

* * * * *

(c)(1) There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, and primary frequency response service if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of operating reserve-spinning and operating reserve-supplemental services if the Seller passes these two indicative market power screens and demonstrates in its market-based rate application how the scheduling practices in its region support the delivery of operating reserve resources from one balancing authority area to another. There will be a rebuttable presumption that a Seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, operating reserve-spinning service, operating reserve-supplemental service, and primary frequency response service if it fails either screen.

* * * * *

[FR Doc. 2015–30140 Filed 11–25–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM15–16–000, Order No. 817]

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: The Commission approves revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation, which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The Commission also directs NERC to make three modifications to the standards within 18 months of the effective date of the final rule.

DATES: This rule will become effective January 26, 2016.

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SUPPLEMENTARY INFORMATION:

Order No. 817

Final Rule

(Issued November 19, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements and improve efficiency by incorporating the necessary requirements from the eight currently-effective TOP Reliability Standards into three comprehensive Reliability Standards. Further, the standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the proposed standards that apply to transmission operators for the TOP standards and reliability coordinators for the IRO standards. Thus, we conclude that there are benefits to clarifying and bringing efficiencies to the TOP and IRO Reliability Standards, consistent with the Commission's policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[2]

2. The Commission also finds that NERC has adequately addressed the concerns raised by the Commission in the Notice of Proposed Rulemaking issued in November 2013 concerning the proposed treatment of system operating limits (SOLs) and interconnection reliability operating limits (IROLs) and concerns about outage coordination.[3] Further, the Commission approves the definitions for operational planning analysis and real-time assessment, the implementation plans and the violation severity level and violation risk factor assignments. However, the Commission directs NERC to make three modifications to the standards as discussed below within 18 months of the effective date of this Final Rule.

3. We also address below the four issues for which we sought clarifying comments in the June 18, 2015, Notice of Proposed Rulemaking (NOPR) proposing to approve the TOP and IRO Reliability Standards: (A) Possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP–001–3; and (D) data exchange capabilities. In addition we address other issues raised by commenters.

I. Background

A. Regulatory Background

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[4] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[5] In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[6]

5. The Commission approved the initial TOP and IRO Reliability Standards in Order No. 693.[7] On April 16, 2013, in Docket No. RM13–14–000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.[8] Additionally, on April 16, 2013, in Docket No. RM13–15–000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had ''removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.'' [9] The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

B. NERC Petition

6. On March 18, 2015, NERC filed a petition with the Commission for approval of the proposed TOP and IRO Reliability Standards.[10] As explained in the Petition, the proposed Reliability Standards consolidate many of the currently-effective TOP and IRO Reliability Standards and also replace the TOP and IRO Reliability Standards that were the subject of the Remand NOPR. NERC stated that the proposed Reliability Standards include

[1] 16 U.S.C. 824o (2012).

[2] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[3] Monitoring System Conditions—*Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards*, Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013) (Remand NOPR). Concurrent with filing the proposed TOP/IRO standards in the immediate proceeding, NERC submitted a motion to withdraw the earlier petition that was the subject of the Remand NOPR. No protests to the motion were filed and the petition was withdrawn pursuant to 18 CFR 385.216(b).

[4] 16 U.S.C. 824o(c) and (d).

[5] *See id.* 16 U.S.C. 824o(e).

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[7] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 508, *order on reh'g*, Order No. 693–A, 120 FERC ¶ 61,053 (2007). In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards. *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

[8] On April 5, 2013, in Docket No. RM13–12–000, NERC proposed revisions to Reliability Standard TOP–006–3 to clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources.

[9] Remand NOPR, 145 FERC ¶ 61,158 at P 4.

[10] The TOP and IRO Reliability Standards are not attached to the Final Rule. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket No. RM15-16 and is posted on the ERO's Web site, *available at: http://www.nerc.com.*

improvements over the currently-effective TOP and IRO Reliability Standards in (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data. NERC stated that the proposed TOP and IRO Reliability Standards address outstanding Commission directives relevant to the proposed TOP and IRO Reliability Standards. NERC stated that the proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. NERC explained that the proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. NERC contended that the proposed Reliability Standards help to ensure that reliability coordinators and transmission operators work together, and with other functional entities, to operate the bulk electric system within SOLs and IROLs.[11] NERC also provided explanations of how the proposed Reliability Standards address the reliability issues identified in the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations (''2011 Southwest Outage Blackout Report'').

7. NERC proposed three TOP Reliability Standards to replace the existing suite of TOP standards. The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of transmission operators, with certain requirements applying to the roles and responsibilities of the balancing authority. Among other things, NERC stated that the proposed revisions to the TOP Reliability Standards help ensure that transmission operators plan and operate within all SOLs. The proposed IRO Reliability Standards, which complement the proposed TOP Standards, are designed to ensure that the bulk electric system is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions. The proposed IRO Reliability Standards set forth the responsibility and authority of reliability coordinators to provide for reliable operations. NERC stated that, in the proposed IRO Reliability Standards, reliability coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require reliability coordinators to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.

8. NERC also proposed revised definitions for ''operational planning analysis'' and ''real-time assessment.'' For all standards except proposed Reliability Standards TOP–003–3 and IRO–010–2, NERC proposed the effective date to be the first day of the first calendar quarter twelve months after Commission approval. According to NERC's implementation plan, for proposed TOP–003–3, all requirements except Requirement R5 will become effective on the first day of the first calendar quarter nine months after the date that the standard is approved. For proposed IRO–010–2, Requirements R1 and R2 would become effective on the first day of the first calendar quarter that is nine months after the date that the standard is approved. Proposed TOP–003–3, Requirement R5 and IRO–010–2, Requirement R3 would become effective on the first day of the first calendar quarter twelve months after the date that the standard is approved. The reason for the difference in effective dates for proposed TOP–003–3 and IRO–010–2 is to allow applicable entities to have time to properly respond to the data specification requests from their reliability coordinators, transmission operators, and/or balancing authorities.

C. Notice of Proposed Rulemaking

9. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking proposing to approve the TOP and IRO Reliability Standards pursuant to FPA section 215(d)(2), along with the two new definitions referenced in the proposed standards, the assigned violation risk factors and violation severity levels, and the proposed implementation plan for each standard.[12]

10. In the NOPR, the Commission explained that the proposed TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The Commission also proposed to find that NERC has adequately addressed the concerns raised by the Remand NOPR issued in November 2013.

11. In the NOPR, the Commission also discussed the following specific matters and asked for further comment: (A) Possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP–001–3; and (D) data exchange capabilities.

12. Timely comments on the NOPR were filed by: NERC; Arizona Public Service Company (APS), Bonneville Power Administration (BPA), Dominion Resources Services, Inc. (Dominion), the Edison Electric Institute (EEI); Electric Reliability Council of Texas, Inc. (ERCOT), Independent Electricity System Operator (IESO), ISO/RTOs,[13] International Transmission Company (ITC); Midcontinent Independent System Operator, Inc., Northern Indiana Public Service Company (NIPSCO), Occidental Energy Ventures, LLC (Occidental), Peak Reliability (Peak), and Transmission Access Policy Study Group (TAPS).

II. Discussion

13. Pursuant to section 215(d) of the FPA, we adopt our NOPR proposal and approve NERC's revisions to the TOP and IRO Reliability Standards, including the associated definitions, violation risk factors, violation severity levels, and implementation plans, as just, reasonable, not unduly discriminatory or preferential and in the public interest. We note that all of the commenters that address the matter support, or do not oppose, approval of the revised suite of TOP and IRO Reliability Standards. We determine that NERC's approach of consolidating requirements and removing redundancies generally has merit and is consistent with Commission policy

[11] The NERC Glossary of Terms defines IROL as ''[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.'' In turn, NERC defines SOL as ''[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. . . .''

[12] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 151 FERC ¶ 61,236 (2015) (NOPR).

[13] ISO/RTOs include Independent Electricity System Operator, ISO New England Inc., Midcontinent Independent System Operator, New York Independent System Operator, Inc., PJM Interconnection LLC, and Southwest Power Pool, Inc.

promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[14]

14. We also determine that the proposed TOP and IRO Reliability Standards should improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators.[15] The proposed TOP Reliability Standards will eliminate multiple TOP standards, resulting in a more concise set of standards, reducing redundancy and more clearly delineating responsibilities between applicable entities. In addition, we find that the proposed Reliability Standards provide a comprehensive framework as well as important improvements to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. The TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions.

15. In the NOPR, the Commission proposed to find that NERC adequately addressed the concerns raised by the Commission in the Remand NOPR with respect to (1) the treatment of SOLs in the proposed TOP Reliability Standards, and (2) the IRO standards regarding planned outage coordination, both of which we address below.

Operational Responsibilities and Actions of SOLs and IROLs

16. In the Remand NOPR, the Commission expressed concern that the initially proposed (now withdrawn) TOP standards did not have a requirement for transmission operators to plan and operate within all SOLs. The Commission finds that the TOP Reliability Standards that NERC subsequently proposed address the Commission's Remand NOPR concerns by requiring transmission operators to plan and operate within all SOLs, and to monitor and assess SOL conditions within and outside a transmission operator's area. Further, the TOP/IRO Standards approved herein address the possibility that additional SOLs could develop or occur in the same-day or real-time operational time horizon and, therefore, would pose an operational risk to the interconnected transmission network if not addressed. Likewise, the Reliability Standards give reliability coordinators the authority to direct actions to prevent or mitigate instances of exceeding IROLs because the primary decision-making authority for mitigating IROL exceedances is assigned to reliability coordinators while transmission operators have the primary responsibility for mitigating SOL exceedances.[16]

17. Furthermore, the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs, IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.[17]

Outage Coordination

18. In the NOPR, the Commission explained that NERC had addressed concerns raised in the Remand NOPR with respect to the IRO standards regarding planned outage coordination. In the Remand NOPR, the Commission expressed concern with NERC's proposal because Reliability Standards IRO–008–1, Requirement R3 and IRO–010–1a (subjects of the proposed remand and now withdrawn by NERC) did not require the coordination of outages, noting that outage coordination is a critical reliability function that should be performed by the reliability coordinator.[18]

19. In the NOPR, the Commission noted that Reliability Standard IRO–017–1, Requirement R1 requires each reliability coordinator to develop, implement and maintain an outage coordination process for generation and transmission outages within its reliability coordinator area. Additionally, Reliability Standard IRO–014–3, Requirement R1, Part 1.4 requires reliability coordinators to include the exchange of planned and unplanned outage information to support operational planning analyses and real-time assessments in the operating procedures, processes, and plans for activities that require coordination with adjacent reliability coordinators. We believe that these proposed standards adequately address our concerns with respect to outage coordination as outlined in the Remand NOPR. However, as we discuss below we direct NERC to modify the standards to include transmission operator monitoring of non-BES facilities, and to specify that data exchange capabilities include redundancy and diverse routing; as well as testing of the alternate or less frequently used data exchange capability, within 18 months of the effective date of this Final Rule.

20. Below we discuss the following matters: (A) Possible inconsistencies of identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity function from proposed Reliability Standard TOP–001–3; (D) data exchange capabilities, and (E) other issues raised by commenters.

A. Possible Inconsistences in IROLs Across Regions

NOPR

21. In the NOPR, the Commission noted that in Exhibit E (SOL White Paper) of NERC's petition, NERC stated that, with regard to the SOL concept, the SOL White Paper brings ''clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.'' [19] The Commission further noted that IROLs, as defined by NERC, are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system. The Commission agreed with NERC that clarity and consistency are important with respect to establishing and implementing operating plans to mitigate SOL and IROL exceedances. However, the Commission noted that NERC, in its 2015 State of Reliability report, had stated that the Western Interconnection reliability coordinator definition of an IROL has additional criteria that may not exist in other reliability coordinator areas.[20] The

[14] *See* Order No. 788, 145 FERC ¶ 61,147.

[15] *See, e.g.,* Order No. 748, 134 FERC ¶ 61,213, at PP 39–40.

[16] *See* Remand NOPR, 145 FERC ¶ 61,158 at P 85. Further, currently-effective Reliability Standard IRO–009–1, Requirement R4 states that ''[w]hen actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv.''

[17] NERC Petition at 17–18.

[18] Remand NOPR, 145 FERC ¶ 61,158 at P 90.

[19] NERC Petition, Exhibit E, ''White Paper on System Operating Limit Definition and Exceedance Clarification'' at 1.

[20] NOPR, 151 FERC ¶ 61,236 at P 51, citing NERC 2015 State of Reliability report at 44, *available at www.nerc.com. See also* WECC Reliability Coordination System Operating Limits Methodology for the Operations Horizon, Rev. 7.0 (effective March 3, 2014) at 18 (stating that ''SOLs

Commission stated that it is unclear whether NERC regions apply a consistent approach to identifying IROLs. The Commission, therefore, sought comment on (1) identification of all regional differences or variances in the formulation of IROLs; (2) the potential reliability impacts of such differences or variations, and (3) the value of providing a uniform approach or methodology to defining and identifying IROLs.

Comments

22. Commenters generally agree that there are variations in IROL formulation but maintain that the flexibility is needed due to different system topographies and configurations. EEI and other commenters, also suggest that, to the extent there are variations, such resolution should be addressed by NERC and the Regional Entities in a standard development process rather than by a Commission directive. NERC requests that the Commission refrain from addressing these issues in this proceeding. NERC contends that the TOP and IRO Reliability Standards do not address the methods for the development and identification of SOLs and IROLs and that requirements governing the development and identification of SOLs and IROLs are included in the Facilities Design, Connections and Maintenance (FAC) Reliability Standards. NERC states that the current FAC Reliability Standards provide reliability coordinators flexibility in the manner in which they identify IROLs.[21] NERC adds that it recently initiated a standards development project (Project 2015–09 Establish and Communicate System Operating Limits) to evaluate and modify the FAC Reliability Standards that address the development and identification of SOLs and IROLs. NERC explains that the Project 2015–09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs. According to NERC, it would be premature for NERC or the Commission to address issues regarding the identification of IROLs in this proceeding without the benefit of the complete analysis of the Project 2015–09 standard drafting team. NERC commits to working with stakeholders and Commission staff during the Project 2015–09 standards development process to address the issues raised in the NOPR.

23. ERCOT comments that the existing Reliability Standards provide a consistent but flexible structure for IROL identification that provides maximum benefit to interconnected transmission network. ERCOT believes that the Reliability Standards should continue to permit regional variations that will encourage flexibility for consideration of system-specific topology and characteristics as well as the application of operational experience and engineering judgment. ERCOT states that regional differences exist in terms of the specific processes and methodologies utilized to identify IROLs. However, according to ERCOT, appropriate consistency in IROL identification is driven by the definition of an IROL, the Reliability Standards associated with the identification of SOLs, and the communication and coordination among responsible entities. Further, ERCOT argues that allowing regional IROL differences benefits the bulk electric system by allowing the entities with the most operating experience to recognize the topology and operating characteristics of their areas, and to incorporate their experience and judgment into IROL identification.

24. Peak supports allowing regions to vary in their interpretation and identification of IROLs based on the level of risk determined by that region, as long as that interpretation is transparent and consistent within that region. Peak understands the definition of IROL to recognize regional differences and variances in the formulation of IROLs. Peak contends that such regional variation is necessary due to certain physical system differences. Thus, according to Peak, a consistent approach from region to region is not required, and may not enhance the overall reliability of the system. Peak explains that, in the Western United States, the evaluation of operating limits and stability must take into account the long transmission lines and greater distance between population centers, a situation quite different than the dense, interwoven systems found in much of the Eastern Interconnection. Peak adds that the Western Interconnection more frequently encounters localized instability because of the sparsity of the transmission system and the numerous small load centers supplied by few transmission lines, and these localized instances of instability have little to no impact on the overall reliability of the bulk electric system. Peak encourages the Commission to recognize that differences among the regions may require flexibility to determine, through its SOL methodology, the extent and severity of instability and cascading that warrant the establishment of an IROL.

25. While Peak supports retaining the flexibility of a region by region application of the IROL definition, Peak notes that the current definition is not without some confusing ambiguity in the application of IROL that should be addressed, including ambiguity and confusion around the term ''instability,'' the phrase ''that adversely impact the reliability of the Bulk Electric System'' and ''cascading.'' Peak suggests that one method to eliminate confusion on the definition and application of IROLs would be to expand NERC's whitepaper to address concerns more specific to IROLs. Peak contends that further guidance from NERC in the whitepaper may remedy the confusion on the limits on the application of IROLs for widespread versus localized instability.

26. Peak requests that, if the Commission or NERC determines that a one-size-fits all approach is necessary for the identification of IROLs and eliminates the current flexibility for regional differences, that the Commission recognizes the limitations this will place on reliability coordinators to evaluate the specific conditions within their reliability coordinator area. The Commission should require that any standardized application of the IROL definition would need to address specific thresholds and implementation triggers for IROLs based on the risk profile and challenges facing specific regions, to avoid the downfalls of inaccurate or overbroad application, as discussed above.

Commission Determination

27. While it appears that regional discrepancies exist regarding the manner for calculating IROLs, we accept NERC's explanation that this issue is more appropriately addressed in NERC's Facilities Design, Connections and Maintenance or ''FAC'' Reliability Standards. NERC indicates that an ongoing FAC-related standards development project—NERC Project 2015–09 (Establish and Communicate System Operating Limits)—will address the development and identification of SOLs and IROLs. We conclude that NERC's explanation, that the Project 2015–09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs, is reasonable.

qualify as IROLs when . . . studies indicate that instability, Cascading, or uncontrolled separation may occur resulting in uncontrolled interruption of load equal to or greater than 1000 MW''), *available at https://www.wecc.biz/Reliability/PhaseII%20WECC%20RC%20SOL%20Methodology%20FINAL.pdf.*

[21] *See also* Peak Comments at 4–5. Peak points to Reliability Standards FAC–011–2 and FAC–014–2 as support for regional variation in establishing IROLs.

Therefore, we will not direct further action on IROLs in the immediate TOP and IRO standard-related rulemaking. However, when this issue is considered in Project 2015–19, the specific regional difference of WECC's 1,000 MW threshold in IROLs should be evaluated in light of the Commission's directive in Order No. 802 (approving Reliability Standard CIP–014) to eliminate or clarify the ''widespread'' qualifier on ''instability'' as well as our statement in the Remand NOPR that ''operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability.'' [22]

B. Monitoring of Non-Bulk Electric System Facilities

NOPR

28. In the NOPR the Commission proposed to find that the proposed Reliability Standards adequately address the 2011 Southwest Outage Blackout Report recommendation regarding monitoring sub-100 kV facilities, primarily because of the responsibility of the reliability coordinator under proposed Reliability Standard IRO–002–4, Requirement R3 to monitor non-bulk electric system facilities to the extent necessary. The Commission noted, however, that ''the transmission operator may have a more granular perspective than the reliability coordinator of its necessary non-bulk electric system facilities to monitor,'' and it is not clear whether or how the transmission operator would provide information to the reliability coordinator regarding which non-BES facilities should be monitored.[23] The Commission sought comment on how NERC will ensure that the reliability coordinator will receive such information.

29. The Commission stated that including such non-bulk electric system facilities in the definition of bulk electric system through the NERC Rules of Procedure exception process could be an option to address any potential gaps for monitoring facilities but notes that there may be potential efficiencies gained by using a more expedited method to include non-bulk electric system facilities that requires monitoring. The Commission sought comment on whether the BES exception process should be used exclusively in all cases. Alternatively, the Commission sought comment on whether this concern can be addressed through a review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring.

Comments

30. Nearly all commenters support the Reliability Standards as proposed as sufficient for identifying and monitoring non-bulk electric system facilities, and do not support the alternatives offered by the Commission in the NOPR.[24] NERC submits that the proposed data specification and collection Reliability Standards IRO–010–2 and TOP–003–3, in addition to the exceptions process will help ensure that the reliability coordinator can work with transmission operators, and other functional entities, to obtain sufficient information to identify the necessary non-bulk electric system facilities to monitor. In support, NERC points to Reliability Standard IRO–010–2, which provides a mechanism for the reliability coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or cascading outages. Further, NERC cites Reliability Standard TOP–003–3, which allows transmission operators to obtain data on non-bulk electric system facilities, necessary to perform their operational planning analyses, real-time monitoring, and real-time assessments from applicable entities. NERC explains that any data that the transmission operator obtains regarding non-bulk electric system facilities under Reliability Standard TOP–003–3 can be passed on to the reliability coordinator pursuant to a request under proposed Reliability Standard IRO–010–2. Accordingly, NERC states that it would be premature to develop an alternative process before the data specification and bulk electric system exception process are allowed to work.

31. EEI states that this issue has been thoroughly studied by NERC through Project 2010–17 Phase 2 (Revisions to the Definition of Bulk Electric System) that led to modification of the definition of bulk electric system. EEI believes that the current process provides all of the necessary tools and processes to ensure that insights by TOPs are fully captured and integrated into existing monitoring systems that would ensure that all non-BES elements that might impact BES reliability are fully monitored. EEI does not support the alternative process proposed by the Commission. EEI warns that an alternative, parallel review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring would either circumvent the revised bulk electric system definition process or arbitrarily impose NERC requirements (*i.e.*, monitoring) onto non-bulk electric system elements.

32. APS agrees with the Commission that there would be a reliability benefit for the reliability coordinator to be able to identify facilities within the transmission operators' areas that may have a material impact on reliability. APS believes this benefit can be achieved using the method deployed in the Western Interconnection by the Western Electricity Coordinating Council (WECC). APS explains that the WECC planning coordination committee has published a bulk electric system inclusion guideline that categorizes non-bulk electric system facilities that are to be identified by each planning authority and transmission planner when performing their system planning and operations reliability assessments, and the identified facilities are then reported to NERC. APS proposes a similar exception process be used in all cases. According to APS, each reliability coordinator would publish a guideline on how to identify non-bulk electric system facilities critical to reliability appropriate for their reliability coordinator area, and each planning coordinator and transmission planner would run studies according to the reliability coordinator guideline at least once every three years.

33. ERCOT states that performance of sufficient studies and evaluations of reliability coordinator areas occurs in cooperation and coordination with associated transmission operators, rending an additional review process unnecessary. However, to avoid any potential gaps in monitoring non-bulk electric system facilities and ensure that existing agreements and monitoring processes are respected, ERCOT states that the Commission should direct NERC to modify the TOP and IRO Reliability Standards to refer not only to sub-100 kV facilities identified as part of the bulk electric system through the Rules of Procedure exception process, but also to other sub-100 kV facilities as requested or agreed by the responsible entities.[25] ERCOT also states that

[22] *Physical Security Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (2014) and Remand NOPR, 145 FERC ¶ 61,158 at P 52. *See also* FPA section 215(a)(4) defining Reliable Operation as ''operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.''

[23] NOPR, 151 FERC ¶ 61,236 at P 58.

[24] *E.g.* NERC, EEI, TAPS, Occidental, and NIPSCO.

[25] *See also* ISO/RTOs Comments at 3.

because ''non-bulk electric system facilities'' fall outside the scope of the NERC Reliability Standards, use of this terminology should be avoided. ERCOT advocates for the Commission to permit monitoring of other sub-100 kV facilities to be undertaken as agreed to between the reliability coordinator and the transmission operator. ERCOT and ISO/RTOs suggest that the phrase ''non-BES facilities'' in Reliability Standard IRO–002–4, Requirement R3 should be replaced with ''sub-100 kV facilities identified as part of the BES through the BES exception process or as otherwise agreed to between the Reliability Coordinator and Transmission Operator'' and the phrase ''non-BES data'' in Reliability Standards IRO–010–2 (Requirement R1.1) and TOP–003–3 (Requirement R1.1) should be replaced with ''data from sub-100 kV facilities identified as part of the BES through the BES exception process, as otherwise requested by the Responsible Entity, or as agreed to between the Transmission Operator and the Responsible Entity.'' [26]

34. ITC does not support the Commission's proposal. ITC states that transmission operators are required to incorporate any non-bulk electric system data into operational planning analysis and real-time assessments and monitoring, which therefore requires transmission operators to regularly review their models to identify impacting non-bulk electric system facilities. Conversely, ITC explains that conducting a one-time or periodic review and analysis of a transmission operator's model ignores the fact that changes in system conditions can cause the list of impacting non-bulk electric system facilities to change frequently.

Commission Determination

35. We agree with NERC, TAPS, and EEI that the BES exception process can be a mechanism for identifying non-BES facilities to be included in the BES definition.[27] Indeed, *once* a non-BES facility is included in the BES definition under the BES exception process, the ''non-BES facility'' becomes a BES ''Facility'' under TOP–001–3, Requirement R10, and real-time monitoring is required of ''Facilities.'' [28] However, we are concerned that in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP–001–3, Requirement R10 creates a reliability gap. As the 2011 Southwest Outage Report indicates, the Regional Entity ''should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and *actively monitored* and alarmed in [real-time contingency analysis] systems.'' [29] Such monitoring of non-BES facilities could provide a ''stop gap'' during the period where a sub-100 kV facility undergoes analysis as a possible BES facility, allowing for monitoring in the interim until such time the non-bulk electric system facilities become ''BES Facilities'' or the transmission operator determines that a non-bulk electric system facility is no longer needed for monitoring to determine a system operating limit exceedance in its area.[30] We believe that the operational planning analyses and real-time assessments performed by the transmission operators as well as the reliability coordinators will serve as the basis for determining which ''non-BES facilities'' require monitoring to determine system operating limit and interconnection reliability operating limit exceedances. In addition, we believe that monitoring of certain non-BES facilities that are occasional system operating limit exceedance performers may not qualify as a candidate for inclusion in the BES definition, yet should be monitored for reliability purposes.[31] Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to revise Reliability Standard TOP–001–3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO–002–4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary. NERC can develop an equally efficient and effective alternative that addresses our concerns.[32]

36. To be clear, we are not directing that all current ''non-BES'' facilities that a transmission operator considers worthy of monitoring also be included in the bulk electric system. We believe that such monitoring may result in some facilities becoming part of the bulk electric system through the exception process; however it is conceivable that others may remain non-BES because they are occasional system operating limit exceedance performers that may not qualify as a candidate for inclusion in the BES definition.

C. Removal of Load-Serving Entity Function From TOP–001–3

NOPR

37. NERC proposed the removal of the load-serving entity function from proposed Reliability Standard, TOP–001–3, Requirements R3 through R6, as a recipient of an operating instruction from a transmission operator or balancing authority. NERC supplemented its initial petition with additional explanation for the removal of the load-serving entity function from proposed Reliability Standard TOP–001–3.[33] NERC explained that the proposed standard gives transmission operators and balancing authorities the authority to direct the actions of certain other functional entities by issuing an operating instruction to maintain reliability during real-time operations.

38. In the NOPR, the Commission noted that NERC was required to make a compliance filing in Docket No. RR15–4–000, regarding NERC's Risk-Based Registration initiative, and that the Commission's decision on that filing

[26] *See also* ISO/RTOs Comments at 4–6.

[27] NERC TOP/IRO Petition, Exh. G at 9 states in response to the 2011 Southwest Outage Recommendation #17, ''If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in proposed TOP–001–3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities.' ''

[28] NERC Glossary of Terms defines Facility as: ''A set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, etc.)''

[29] NOPR, 151 FERC ¶ 61,236 at P 55, citing Recommendation 17 of the 2011 Southwest Outage Blackout Report (emphasis added).

[30] NERC's BES Frequently Asked Questions, Version 1.6, February 25, 2015, Section 5.6. ''How long will the process take?'' at page 14 states: ''In general, assuming a complete application, no appeals, and taking the allotted time for each subtask, the process could take up to 11.5 months, but is anticipated to be shorter for less complicated Exception Requests. If the Exception Request is appealed to the NERC Board of Trustees Compliance Committee pursuant to Section 1703 of the NERC Rules of Procedure, the process could take an additional 8.5 months, totaling 20 months. This does not include timing related to an appeal to the applicable legal authority or Applicable Governmental Authority. A Regional Entity, upon consultation with NERC, may extend the time frame of the substantive review process. . . .'' *http://www.nerc.com/pa/RAPA/BES%20DL/BES%20FAQs.pdf.*

[31] *See, e.g.*, NERC TOP/IRO Petition at 18 and 27–28.

[32] Reliability Standard IRO–002–4, Requirement R3 states: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

[33] The Commission also notes that Reliability Standards TOP–003–3 and IRO–010–2 also include ''load-serving entity'' as an applicable entity.

will guide any action in this proceeding. On March 19, 2015, the Commission approved, in part, NERC's Risk-Based Registration initiative, but denied, without prejudice, NERC's proposal to eliminate the load-serving entity function from the registry process, finding that NERC had not adequately justified its proposal.[34] In doing so, the Commission directed NERC to provide additional information to support this aspect of its proposal to address the Commission's concerns. On July 17, 2015, NERC submitted a compliance filing in response to the March 19 Order.

Comments

39. NERC states that while load-serving entities play a role in facilitating interruptible (or voluntary) load curtailments, that role is to simply communicate requests for voluntary load curtailments and does not necessitate requiring load-serving entities to comply with a transmission operator's or balancing authority's operating instructions issued pursuant to Reliability Standard TOP–001–3. In short, the load-serving entity's role in carrying out interruptible load curtailment is not the type of activity that rises to the level of requiring an operating instruction. EEI and TAPS contend it is appropriate to omit the load-serving entity function from TOP–001–3 applicability. TAPS explains that because the load-serving entity function does not own or operate equipment, the load-serving entity function cannot curtail load or perform other corrective actions subject to reliability standards. Dominion asserts that a load-serving entity does not own or operate bulk electric system facilities or equipment or the facilities or equipment used to serve end-use customers and is not aware of any entity, registered solely as a load-serving entity, which is responsible for operating one or more elements or facilities.

Commission Determination

40. In an October 15, 2015 order in Docket No. RR15–4–001, the Commission accepted a NERC compliance filing, finding that NERC complied with the March 17 Order with respect to providing additional information justifying the removal of the load-serving entity function.[35] The Commission also found that NERC addressed the concerns expressed regarding an accurate estimate of the load-serving entities to be deregistered and the reliability impact of doing so, and how load data will continue to be available and reliability activities will continue to be performed even after load-serving entities would no longer be registered.[36] Because the load-serving entity category is no longer a NERC registration function, no further action is required in this proceeding.[37]

D. Data Exchange Capabilities

41. The Commission approved Reliability Standards COM-001-2 (Communications) and COM–002–4 (Operating Personnel Communications Protocols) in Order No. 808, and noted that in the NOPR underlying that order (COM NOPR) it had raised concerns as to whether Reliability Standard COM–001–2 addresses facilities that directly exchange or transfer data.[38] In response to that concern in the COM NOPR, NERC clarified that Reliability Standard COM–001–2 did not need to include requirements regarding data exchange capability because such capability is covered under other existing and proposed standards. Based on that explanation, the Commission decided not to make any determinations in Order No. 808 and stated that it would address the issue in this TOP and IRO rulemaking proceeding.[39]

NOPR

42. In the NOPR, the Commission stated that facilities for data exchange capabilities appear to be addressed in NERC's TOP/IRO petition. However, the Commission sought additional explanation from NERC regarding how it addresses data exchange capabilities in the TOP and IRO Standards in the following areas: (a) Redundancy and diverse routing; and (b) testing of the alternate or less frequently used data exchange capability.

1. Redundancy and Diverse Routing of Data Exchange Capabilities

NOPR

43. In the NOPR, the Commission agreed that proposed Reliability Standard TOP–001–3, Requirements R19 and R20 require some form of ''data exchange capabilities'' for the transmission operator and balancing authority and that proposed Reliability Standard TOP–003–3 addresses the operational data itself needed by the transmission operator and balancing authority. In addition, the Commission agreed that Reliability Standard IRO–002–4, Requirement R1 requires ''data exchange capabilities'' for the reliability coordinator and that proposed Reliability Standard IRO–010–2 addresses the operational data needed by the reliability coordinator and that proposed Reliability Standard IRO–002–4 Requirement R4 requires a redundant infrastructure for system monitoring. However, the Commission was concerned that it is not clear whether redundancy and diverse routing of data exchange capabilities were adequately addressed in proposed Reliability Standards TOP–001–3 and IRO–002–4 for the reliability coordinator, transmission operator, and balancing authority and sought explanation or clarification on how the standards address redundancy and diverse routing or an equally effective alternative. The Commission also stated that, if NERC or others believe that redundancy and diverse routing are not addressed, they should address whether there are associated reliability risks of the interconnected transmission network for any failure of data exchange capabilities that are not redundant and diversely routed.

Comments

44. NERC and EEI state that the requirements in the TOP and IRO Reliability Standards covering data exchange are results-based, articulating a performance objective without dictating the manner in which it is met. NERC adds that, in connection with their compliance monitoring activities, NERC and the Regional Entities will review whether applicable entities have met that objective, and will consider whether the applicable entity has redundancy and diverse routing, and whether the applicable entity tests these capabilities. EEI also argues that Reliability Standard EOP–008–1, Requirements R1, R1.2, R1.2.2, R7, and EOP–001–2.1b, Requirements R6 and R6.1 provide specific requirements for maintaining or specifying reliable back-up data exchange capability necessary to ensure BES Reliability and the testing of those capabilities.

45. ERCOT asserts that the Reliability Standards already appropriately provide for redundancy and diversity of routing of data exchange capabilities, as both the existing and proposed standards

[34] *North American Electric Reliability Corp.* 150 FERC ¶ 61,213 (2015) (March 19 Order).

[35] *North American Electric Reliability Corp*, 153 FERC ¶ 61,024 (2015).

[36] *Id.*

[37] In its response to comments in Docket No. RR15–4–000, NERC stated that, once the Commission approved the proposed deactivation of the load-serving entity registration function, it would make any needed changes to the Reliability Standards through the Reliability Standard Development Process. *See* January 26, 2016, NERC Motion to File Limited Answer at 6 in Docket No. RR15–4–000.

[38] *See* NOPR, 151 FERC ¶ 61,236 at P 67, citing *Communications Reliability Standards*, Order No. 808, 151 FERC ¶ 61,039 (2015).

[39] *Id.* citing Order No. 808, 151 FERC ¶ 61,039 at P 54.

either explicitly or implicitly require responsible entities to ensure availability of data and data exchange capabilities. ERCOT states that, should the Commission seek to provide further clarification on this issue, such clarification should be consistent with existing explicit requirements regarding the redundancy of data exchange capabilities, such as Requirement R4 of Reliability Standard IRO–002–4.

46. ISOs/RTOs and ERCOT explain the suite of currently-effective standards and the proposed TOP and IRO standards establish performance-based requirements for reliability coordinators, balancing authorities, and transmission operators, that create the need for those entities to have diverse and redundantly routed data communication systems. In the event of a failure of data communications, ISOs/RTOs explain that the functional entity should be able to rely on the redundant and diversely routed *voice capabilities* required in the COM standards.

Commission Determination

47. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations. NERC's comprehensive approach to establishing communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here.[40] Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to modify Reliability Standards TOP–001–3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, we direct NERC to clarify that ''redundant infrastructure'' for system monitoring in Reliability Standards IRO–002–4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.

48. Further, we disagree with commenter arguments that Reliability Standard EOP–008–1 provides alternatives to data exchange redundancy and diverse routing. The NERC standard drafting team that developed the COM standards addressed this issue in the standards development process, responding to a commenter seeking clarification on the relationship between communication capabilities, alternative communication capabilities, primary control center functionality and backup control center functionality. The standard drafting team responded that ''Interpersonal Communication and Alternative Interpersonal Communication *are not related to EOP–008*,'' even though Reliability Standard EOP–008–1 Requirement R1 applies equally to data communications and voice communications.[41] To the extent the standard drafting team asserted that Reliability Standard EOP–008 did not supplant the redundancy requirements of the COM Reliability Standards, we believe the same is true for data communications. Redundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communications.

2. Testing of the Alternate or Less Frequently Used Data Exchange Capability

NOPR

49. In the NOPR, the Commission expressed concern that the proposed TOP and IRO Reliability Standards do not appear to address testing requirements for alternative or less frequently used mediums for data exchange to ensure they would properly function in the event that the primary or more frequently used data exchange capabilities failed. Accordingly, the Commission sought comment on whether and how the TOP and IRO Reliability Standards address the testing of alternative or less frequently used data exchange capabilities for the transmission operator, balancing authority and reliability coordinator.

Comments

50. Commenters assert that the existing standards have sufficient testing requirements. NERC points to Reliability Standard EOP–008–1, Requirement R7, which requires that applicable entities conduct annual tests of their operating plan that demonstrates, among other things, backup functionality. Similarly, EEI cites EOP–008–1 Requirements R1, R1.2, R1.2.2, R7 and EOP–001–2.1b Requirements R6 and R6.1 as providing specific requirements for maintaining and testing of data exchange capabilities. ITC suggests that NERC's proposed Standard TOP–001–3 provides ample assurance that the data exchange capabilities are regularly tested and also points to Reliability Standards EOP–001–2.1b and EOP–008–1 which require entities, including those covered by TOP–001–3, to maintain reliable back-up data exchange capability as necessary to ensure reliable BES operations, and require that such capabilities be thoroughly and regularly tested.

Commission Determination

51. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to test alternate data exchange capabilities. However, we are not persuaded by the commenters' assertions that the need to test is implied in the TOP and IRO Standards. Rather, we determine that testing of alternative data exchange capabilities is important to reliability and should not be left to what may or may not be implied in the standards.[42] Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority. We believe that the structure of Reliability Standard COM–001–2, Requirement R9 could be a

[40] *See, e.g.,* Order No. 808, 151 FERC ¶ 61,039 at P 8: ''NERC stated in its [COM] petition that Reliability Standard COM–001–2 establishes requirements for Interpersonal Communication capabilities necessary to maintain reliability. NERC explained that proposed Reliability Standard COM–001–2 applies to reliability coordinators, balancing authorities, transmission operators, generator operators, and distribution providers. The proposed Reliability Standard includes eleven requirements and two new defined terms, ''Interpersonal Communication'' and ''Alternative Interpersonal Communication,'' that, according to NERC, collectively provide a comprehensive approach to establishing communications capabilities necessary to maintain reliability.''

[41] *See* NERC COM Petition, Exh. M, (Consideration of Comments on Initial Ballot, February 25–March 7, 2011) at 30 (emphasis added).

[42] In NERC's COM Petition, Exh. M, (Consideration of Comments, Index to Questions, Comments and Responses) at 35, the standard drafting team stated that the ''requirement [COM–001–2, Requirement R9 which addresses testing of alternative interpersonal communication] applies to the primary control center'' and ''EOP–008 applies to the back up control center.''

model for use in the TOP and IRO Standards.[43]

E. Other Issues Raised by Commenters

1. Emergencies and Emergency Assistance Under Reliability Standard TOP–001–3

52. Reliability Standard TOP–001–3, Requirement R7 requires each transmission operator to assist other transmission operators within its reliability coordinator area, if requested and able, provided that the requesting transmission operator has implemented its comparable emergency procedures. NIPSCO contends that this requirement limits the ability of an adjacent transmission operator that is located along the seam in another reliability coordinator area from rendering assistance in an emergency because Requirement R7 only requires each transmission operator to assist other transmission operators within its reliability coordinator area. NIPSCO points to Reliability Standard IRO–014–3, Requirement R7 which requires each reliability coordinator to assist other reliability coordinators and, according to NIPSCO, a similar requirement in Reliability Standard TOP–001–3 will make the two sets of requirements consistent with each other.

53. In addition, Reliability Standard TOP–001–3, Requirement R8 states:

> Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

BPA contends that the phrase ''could result in'' in Requirement R8 of TOP–001–3 is overly broad and suggests corrective language underscored below:

> Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in an Emergency, or could result in an Emergency *if a credible Contingency were to occur.*

As an alternative to changing the language of the requirement, BPA asks the Commission to clarify that it is in the transmission operator's discretion to determine what ''could result'' in an emergency, based on the transmission operator's experience and judgment.

Commission Determination

54. With regard to NIPSCO's concern, we do not believe that the requirements as written limit the ability of an adjacent transmission operator located along the seam in another reliability coordinator area from rendering assistance in an emergency. We agree with NIPSCO that proposed Reliability Standard TOP–001–3, Requirement R7 requires each transmission operator to assist other transmission operators within its reliability coordinator area and further agree with NIPSCO that proposed Reliability Standard IRO–014–3, Requirement R7 requires each reliability coordinator to assist other reliability coordinators.[44] In addition, we understand that an adjacent transmission operator in another reliability coordinator area can render assistance when directed to do so by its own reliability coordinator.[45] Having a similar requirement in Reliability Standard TOP–001–3 compared to Reliability Standard IRO–014–3, Requirement R7 is unnecessary and could complicate the clear decision-making authority NERC developed in the TOP and IRO Reliability Standards. Thus, we determine that no further action is required.

55. With regard to clarification of emergencies in Reliability Standard TOP–001–3, Requirement R8, we do not see a need to modify the language as suggested by BPA. The requirement as written implies that the transmission operator has discretion to determine what could result in an emergency, based on its experience and judgment. In addition, we note that the transmission operators' required next-day operational planning analysis, real-time assessments and real-time monitoring under the TOP Reliability Standards provide evaluation, assessment and input in determining what ''could result'' in an emergency.

2. Reliability Coordinator Authority in Next-Day Operating Plans

56. Reliability Standard TOP–002–4, Requirements R2 and R4 require transmission operators and balancing authorities to have operating plans. Reliability Standard TOP–002–4, Requirements R6 and R7 require transmission operators and balancing authorities to provide their operating plans to their reliability coordinators and Reliability Standard IRO–008–2, Requirement R2 requires reliability coordinators to develop a coordinated operating plan that considers the operating plans provided by the transmission operators and balancing authorities.

57. NIPSCO is concerned about the absence of any required direct coordination between transmission operators and balancing authorities as well as the absence of any guidance regarding the resolution of potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO contends that the Reliability Standards provide only a limited coordination process in which reliability coordinators are required to notify those entities identified with its coordinated operating plan of their roles. NIPSCO argues that there is no provision for modifications to operating plans based on the reliability coordinator's coordinated operating plan or based on potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO is concerned that a potential disconnect between operating plans could lead to confusion or a failure of coordination of reliable operations.

Commission Determination

58. We believe that proposed Reliability Standards TOP-002-4 and IRO-008-2 along with NERC's definition of reliability coordinator address NIPSCO's concern.[46] Although the transmission operator and balancing authority develop their own operating plans for next-day operations, both the transmission operator and balancing authority notify entities identified in the operating plans as to their role in those plans. Further, each transmission operator and balancing authority must provide its operating plan for next-day operations to its reliability coordinator.[47] In Reliability Standard IRO-008-2, Requirement R2, the reliability coordinator must have a coordinated operating plan for next-day operations to address potential SOL and IROL exceedances while considering the operating plans for the next-day provided by its transmission operators

[43] 43 COM–001–2, Requirement R9 states: ''Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours.''

[44] *See* Reliability Standards TOP–001–3 and IRO–014–3.

[45] *See* Reliability Standard IRO–001–4, Requirement R2.

[46] NERC Glossary of Terms defines the Reliability Coordinator as ''The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.''

[47] Reliability Standard TOP-002-4 (Operations Planning).

and balancing authorities. Also, Reliability Standard IRO-008-2, Requirement R3 requires that the reliability coordinator notify impacted entities identified in its operating plan as to their role in such plan. Based on the notification and coordination processes of Reliability Standards TOP-002-4 (for the transmission operator and balancing authority) and IRO-008-2 (for the reliability coordinator) for next-day operating plans, as well as the fact that the reliability coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, we believe that the reliability coordinator has the authority and necessary next-day operational information to resolve any next-day operational issues within its reliability coordinator area. Accordingly, we deny NIPSCO's request.

3. Reliability Coordinator Authority in Next-Day Operations and the Issuance of Operating Instructions

59. NIPSCO is concerned with the elimination of the explicit requirement in currently-effective Reliability Standard IRO-004-2 that each transmission operator, balancing authority, and transmission provider comply with the directives of a reliability coordinator based on next-day assessment in the same manner as would be required in real-time operating conditions. NIPSCO claims that, while the Reliability Standards appear to address the Commission's concerns regarding directives issued in other than emergency conditions through the integration of the term ''operating instruction,'' the standards only allow for the issuance of directives in real-time. NIPSCO points to Reliability Standard TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, where transmission operators, balancing authorities, and reliability coordinators are explicitly given authority and responsibility to issue operating instructions to address reliability in their respective areas. NIPSCO states that ''operating instruction'' is ''clearly limited to real-time operations'' as it underscored below:

A command by operating personnel responsible for the *Real-time operation* of the interconnected Bulk Electric System *to change or preserve the state, status, output, or input of an Element* of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

NIPSCO contends that there are no clear requirements addressing potential conflicts between operating plans, no clear requirements authorizing the issuance of a directive to address issues identified in next-day planning, and no clear requirement to comply with any directive so issued. NIPSCO is concerned that this raises the possibility that potential next-day problems identified in the operational planning analyses may not get resolved in the next-day planning period because the reliability coordinator's authority to issue operating instructions is limited to real-time operation. According to NIPSCO, this limitation undermines some of the usefulness of the next-day planning and the performance of operational planning analyses.

Commission Determination

60. We do not share NIPSCO's concern. Rather, we believe that, because the reliability coordinator is required to have a coordinated operating plan for the next-day operations, the reliability coordinator will perform its task of developing a coordinated operating plan in good faith, with inputs not only from its transmission operators and balancing authorities, but also from its neighboring reliability coordinators.[48] A reliability coordinator has a wide-area view and bears the ultimate responsibility to maintain the reliability within its footprint, ''including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.''[49]

61. In addition, we do not agree with NIPSCO's claim that operating instructions are ''clearly limited to real-time operations.'' The phrase ''real-time operation'' in the definition of operating instruction as emphasized by NIPSCO applies to the entity that issues the operating instruction which is ''operating personnel responsible for the Real-time operation.'' The definition of operating instruction is ''[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System. . . .'' In addition, the time horizons associated with the issuance of or compliance with an operating instruction are not found in the definition of operating instructions, but found in the individual requirement(s) applicable to issuing an operating instruction. For example, Reliability Standard TOP-001-3, Requirements R1 through R6 and IRO-001-4, Requirements R1 through R3 are all requirements associated with the issuance or compliance of operating instructions. In all nine requirements, the defined time horizon is ''same-day operations'' and ''real-time operations.''[50] Accordingly, we deny NIPSCO's request on this issue.

4. Updating Operational Planning Analyses and Real-Time Assessments

62. NIPSCO is concerned that the proposed Reliability Standards are not clear as to whether updates or additional analyses are required. NIPSCO points to Reliability Standards IRO-008-2 and TOP-002-4, which require reliability coordinators to perform—and transmission operators and balancing authorities to have—an operational analysis for the next-day, but do not specify when such analysis must be performed or if it needs to be updated in next-day planning based on any change in inputs. Similarly, NIPSCO asserts that the proposed Reliability Standards require the performance of a real-time assessment every 30 minutes but do not address the need to potentially update operating plans based on changes in system conditions (including unplanned outages of protection system degradation) and do not require the performance of additional real-time assessments or other studies with more frequency based on changes in system conditions. NIPSCO explains that it is not clear if or when, based on the operational planning analysis results, some type of additional study or analysis would need to be undertaken prior to the development of an operating plan. According to NIPSCO, the text of the requirements and the definition do not specifically require additional studies; however, it seems that when issues associated with protection system degradation or outages are identified, further study of these issues would be required and/or additional analyses required to update results as protection system status or transmission or generation outages change.

Commission Determination

63. We do not share NIPSCO's concern. Reliability Standards IRO-008-2 and TOP-002-4 require reliability coordinators to perform and

[48] *See* Reliability Standards IRO-008-2, Requirements R1 and R2, and IRO-014-3, Requirement R1.

[49] *See supra* n. 46.

[50] NERC's ''Time Horizons'' document defines ''Same-Day Operations'' time horizon as ''routine actions required within the timeframe of a day, but not real-time'' and defines ''Real-Time Operations'' time horizon as ''actions required within one hour or less to preserve the reliability of the bulk electric system.'' *See http://www.nerc.com/files/Time_Horizons.pdf.*

transmission operators to have an operational planning analysis to assess whether its planned operations for next-day will exceed any of its SOLs (for the transmission operator) and SOLs/IROLs (for the reliability coordinator). Both are required to have an operating plan(s) to address potential SOL and/or IROL exceedances based on its operational planning analysis results. We believe that, if the applicable inputs of the operational planning analysis change from one operating day to the next operating day, and because an operational planning analysis is an ''evaluation of projected system conditions,'' a new operational planning analysis must be performed to include the change in applicable inputs. Based on the results of the new operational planning analysis for next-day, operating plans may need updating to reflect the results of the new operational planning analysis. Likewise with the real-time assessment, as system conditions change and the applicable inputs to the real-time assessment change, a new assessment would be needed to accurately reflect applicable inputs, as stated in the real-time assessment definition.[51]

5. Performing a Real-Time Assessment When Real-Time Contingency Analysis Is Unavailable

64. Reliability Standard TOP-001-3, Requirement R13 requires transmission operators to ensure a real-time assessment is performed at least every 30 minutes. NIPSCO states that NERC's definition of real-time assessment anticipates that real-time assessments must be performed through the use of either an internal tool or third-party service.[52] NIPSCO believes that compliance with the requirement to perform a real-time assessment should not be dependent on the availability of a system or tool. According to NIPSCO, if a transmission operators' tools are unavailable for 30 minutes or more, they should be permitted to meet the requirement to assess existing conditions through other means.

Commission Determination

65. Reliability Standard TOP-001-3, Requirement R13 requires the transmission operator to ensure the assessment is performed at least once every 30 minutes, but does not state that the transmission operator on its own must perform the assessment and does not specify a system or tool. This gives the transmission operator flexibility to perform its real-time assessment. Further supporting this flexibility, NERC's definition of real-time assessment states that a real-time assessment ''may be provided through internal systems or through third-party services.''[53] Therefore, we believe that Reliability Standard TOP-001-3, Requirement R13 does not specify the system or tool a transmission operator must use to perform a real-time assessment. In addition, NERC explains that Reliability Standard TOP-001-3, Requirement R13 and the definition of real-time assessment ''do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa.''[54] Accordingly, we conclude that TOP-001-3 adequately addresses NIPSCO's concern, namely, if a transmission operators' tools are unavailable for 30 minutes or more, the transmission operator has the flexibility to meet the requirement to assess system conditions through other means.

6. Valid Operating Limits

66. IESO is concerned that the revised TOP standards do not compel an entity to verify existing limits or re-establish limits following an event that results in conditions not previously assessed within an acceptable time frame as is specified in the currently-effective Reliability Standard TOP-004-2 Requirement R4.[55] IESO disagrees that this is sufficient because there is no requirement in the Reliability Standard TOP-001-3 standard to derive a new set of limits, particularly transient stability limits, or verify that an existing set of limits continue to be valid for the prevailing conditions within an established timeframe. IESO contends that a real-time assessment is useful only if the system conditions are assessed against a valid set of limits and is unable to verify or re-establish stability-restricted SOLs with which to assess system conditions to address reliability concerns. IESO believes that an explicit requirement to verify or re-establish SOLs when entering into an unstudied state must therefore be imposed to fill this reliability gap.

67. Further, IESO asserts that implementing operating plans to mitigate an SOL exceedance does not require transmission operators to determine a valid set of limits with which to compare the prevailing system conditions (*i.e.* whether or not the limits are exceeded). While the IESO supports performing a real-time assessment every 30 minutes, it asserts that performing an assessment without first validating the current set of limits or re-establishing a new set of limits as the boundary conditions leaves a reliability gap.

Commission Determination

68. We agree with IESO that valid operating limits, including transient stability limits, are essential to the reliable operation of the interconnected transmission network and that a transmission operator must not enter into an unknown operating state. Further, we agree with IESO that Reliability Standard TOP-001-3 has no requirements to derive a new set of limits or verify an existing set of limits for prevailing operating conditions within an established timeframe. However, IESO's concerns regarding the establishment of transient stability operating limits are addressed collectively through proposed Reliability Standard TOP-001-3, certain currently-effective Facilities Design, Connections, and Maintenance (FAC) Reliability Standards and NERC's Glossary of Terms definition of SOLs.

69. In its SOL White Paper, NERC stated that the intent of the SOL concept is to bring clarity and consistency for establishing SOLs, exceeding SOLs, and implementing operating plans to mitigate SOL exceedances.[56] In

[51] Real-time assessment is defined as ''An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: Load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.).''

[52] *See supra* n. 48.

[53] NERC TOP/IRO Petition at 18.

[54] NERC TOP/IRO Petition, Exh. K (Summary of Development History and Complete Record of Development), Consideration of Comments May 19, 2014 through July 2, 2014) at 61.

[55] Requirement R4 states: ''If a Transmission Operator enters an unknown operating state (*i.e.* any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.''

[56] NERC Petition, Exh. E (White Paper on System Operating Limit Definition and Exceedance Clarification) at 1. NIPSCO requests clarification as to how NERC's SOL White Paper can be used in

addition, "transient stability ratings" are included in the SOL definition. Further, in the SOL White Paper, NERC states that the "concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2 and FAC-014-2." [57] Specific to IESO's concerns of establishing transient stability limits, we agree with NERC that approved Reliability Standard FAC-011-2, Requirement R2 requires that the reliability coordinator's SOL methodology include a requirement that SOLs provide a certain level of bulk electric system performance including among other things, that the "BES shall demonstrate transient, dynamic and voltage stability" and that "all Facilities shall be within their . . . stability limits" for both pre- and post-contingency conditions.[58] In addition, we note that currently-effective Reliability Standard FAC-011-2, Requirement R2.1 states that "[i]n the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall *reflect changes to system topology* such as Facility outages." [59]

70. With respect to Reliability Standard TOP-001-3, we agree with NERC that Requirement R13 specifies that transmission operators must perform a real-time assessment at least once every 30 minutes, which by definition is an evaluation of system conditions to assess existing and potential operating conditions. The real-time assessment provides the transmission operator with the necessary knowledge of the system operating state to initiate an operating plan, as specified in Requirement R14, when necessary to mitigate an exceedance of SOLs. In addition, the SOL White Paper provides technical guidance for including timelines in the required operating plans to return the system to within prescribed ratings and limits.[60] Accordingly, we conclude that the establishment of transient stability operating limits is adequately addressed collectively through proposed Reliability Standard TOP-001-3, currently-effective Reliability Standards FAC-011-2 and FAC-014-2 and NERC's Glossary of Terms definition of SOLs.[61]

III. Information Collection Statement

71. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[62] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[63] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a 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.

Public Reporting Burden: The number of respondents below is based on an estimate of the NERC compliance registry for the balancing authority, transmission operator, generator operator, distribution provider, generator owner, load-serving entity, purchasing-selling entity, transmission service provider, interchange authority, transmission owner, reliability coordinator, planning coordinator, and transmission planner functions. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 15, 2015. According to the registry, there are 11 reliability coordinators, 99 balancing authorities, 450 distribution providers, 839 generator operators, 80 purchasing-selling entities, 446 load-serving entities, 886 generator owners, 320 transmission owners, 24 interchange authorities, 75 transmission service providers, 68 planning coordinators, 175 transmission planners and 171 transmission operators. The estimates are based on the change in burden from the current standards to the standards approved in this Final Rule. The following table illustrates the burden to be applied to the information collection:

RM15–16–000 (TRANSMISSION OPERATIONS RELIABILITY STANDARDS, INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS)

	Number of respondents [64] (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden & cost per response [65] (4)	Total annual burden hours & total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
FERC–725A						
TOP–001–3	196 (TOP & BA)	1	196	96 hrs., $6,369	18,816 hrs., $1,248,441.	96 hrs, $6,369.
TOP–002–4	196 (TOP & BA)	1	196	284 hrs., $18,843	55,664 hrs., $3,693,306.	284 hrs., $18,843.
TOP–003–3	196 (TOP & BA)	1	196	230 hrs., $15,260	45,080 hrs., $2,991,058.	230 hrs., $15,260.
Sub-Total for FERC–725A.					123,252 hrs., $7,932,806.	

determining compliance. NIPSCO requests that any substantive content that is treated as containing enforceable compliance requirements be filed with the Commission for approval. NERC developed the SOL White Paper as a guidance document which provides links between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective operating plans to mitigate SOL exceedances. Guidelines are illustrative but not mandatory and enforceable compliance requirements. *See, e.g. North American Electric Reliability Corp.*, 143 FERC ¶ 61,271, at P 15 (2013). Accordingly, we see no need for further revisions to the Reliability Standards to incorporate the SOL White Paper as requested by NIPSCO.

[57] NERC Petition, Exh. E at 1.

[58] *Id.* at 2. *See also* Reliability Standard FAC-011-2, Requirement R2.

[59] Reliability Standard FAC-011-1, Requirement R2.1 (emphasis added).

[60] NERC Petition at 57–58.

[61] *See* Reliability Standard FAC-014-2, Requirement R2.

[62] 44 U.S.C. 3507(d) (2012).

[63] 5 CFR 1320.11.

RM15–16–000 (TRANSMISSION OPERATIONS RELIABILITY STANDARDS, INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS)—Continued

	Number of respondents[64] (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden & cost per response[65] (4)	Total annual burden hours & total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
			FERC–725Z			
IRO–001–4[66]	177 (RC & TOP)	1	177	0 hrs. $0	0 hrs. $0	0 hrs. $0.
IRO–002–4	11 (RC)	1	11	24 hrs., $1,592	264 hrs., $17,516	24 hrs., $1,592.
IRO–008–2	11 (RC)	1	11	228 hrs., $15,127	2,508 hrs., $166,405.	228 hrs., $15,127.
IRO–010–2	11 (RC)	1	11	36 hrs., $2,388	396 hrs., $26,274	36 hrs., $2,388.
IRO–014–3	11 (RC)	1	11	12 hrs., $796	132 hrs., $8,758	12 hrs., $796.
IRO–017–1	180 (RC, PC, & TP).	1	180	218 hrs., $14,464	39,240 hrs., $2,603,574.	218 hrs., $14,464.
Sub-Total for FERC–725Z.					42,540 hrs., $2,822,529.00.	
Retirement of current standards currently in FERC–725A.	457(RC, TOP, BA, TSP, LSE, PSE, & IA).	1	457	−223 hrs., −$14,796	−101,911 hrs., −$6,761,794.	−223 hrs., −$14,796.
NET TOTAL of NOPR in RM15–16.					63,881 hrs., $3,993,540.	

Title: FERC–725Z, Mandatory Reliability Standards: IRO Reliability Standards, and FERC–725A, Mandatory Reliability Standards for the Bulk-Power System.

Action: Proposed Changes to Collections.

OMB Control Nos: 1902–0276 (FERC–725Z); 1902–0244 (FERC–725A).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: On-going.

72. *Necessity of the Information and Internal review*: The Commission has reviewed the requirements of Reliability Standards TOP–001–3, TOP–002–4, TOP–003–3, IRO–001–4, IRO–002–4, IRO–008–2, IRO–010–2, IRO–014–3, and IRO–017–1 and made a determination that the standards are necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

73. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, email: *DataClearance@ferc.gov*, phone: (202) 502–8663, fax: (202) 273–0873].

74. Comments on the requirements of this rule may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at the following email address: *oira_submission@omb.eop.gov*. Please reference OMB Control Nos. 1902–0276 (FERC–725Z) and 1902–0244 (FERC–725A)) in your submission.

IV. Environmental Analysis

75. 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.[67] 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.[68] The actions approved herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

76. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities.[69] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[70] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[71] Reliability Standards TOP–001–3, TOP–002–4, TOP–003–3, IRO–001–4, IRO–002–4, IRO–008–2, IRO–010–2, IRO–014–3, and IRO–017–1 are expected to impose an additional burden on 196 entities (reliability coordinators, transmission operators, balancing authorities, transmission service providers, and planning authorities). Comparison of the applicable entities with the Commission's small business data indicates that approximately 82 of these entities are small entities that will be

[64] the number of respondents is the number of entities for which a change in burden from the current standards to the proposed exists, not the total number of entities from the current or proposed standards that are applicable.

[65] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of April 1, 2015, for an electrical engineer ($66.35/hour). These figures are *available at http://blsgov/oes/current/naics3_221000.htm#17-0000.*

[66] IRO–001–4 is a revised standard with no increase in burden.

[67] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[68] 18 CFR 380.4(a)(2)(ii).

[69] 5 U.S.C. 601–12.

[70] 13 CFR 121.101.

[71] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

affected by the proposed Reliability Standards.[72] As discussed above, Reliability Standards TOP–001–3, TOP–002–4, TOP–003–3, IRO–001–4, IRO–002–4, IRO–008–2, IRO–010–2, IRO–014–3, and IRO–017–1 will serve to enhance reliability by imposing mandatory requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The Commission estimates that each of the small entities to whom the proposed Reliability Standards TOP–001–3, TOP–002–4, TOP–003–3, IRO–001–4, IRO–002–4, IRO–008–2, IRO–010–2, IRO–014–3, and IRO–017–1 applies will incur costs of approximately $147,364 (annual ongoing) per entity. The Commission does not consider the estimated costs to have a significant economic impact on a substantial number of small entities.

VI. Document Availability

77. 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 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

78. 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.

79. 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*.

[72] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 750 employee threshold for each affected entity to conduct a comprehensive analysis.

VII. Effective Date and Congressional Notification

80. This final rule is effective January 26, 2016. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

Issued: November 19, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–30110 Filed 11–25–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF DEFENSE

Department of the Navy

[No. USN–2013–0011]

RIN 0703–AA92

32 CFR Part 776

Professional Conduct of Attorneys Practicing Under the Cognizance and Supervision of the Judge Advocate General; Correction

AGENCY: Department of the Navy, DoD.

ACTION: Final rule; correction.

SUMMARY: On November 4, 2015, the Department of the Navy (DoN) published a final rule to comport with current policy as stated in JAG Instruction 5803.1 (Series) governing the professional conduct of attorneys practicing under the cognizance and supervision of the Judge Advocate General. The content of one of its CFRs is better codified as an appendix, and this correction amends the CFR accordingly.

DATES: This correction is effective December 4, 2015.

FOR FURTHER INFORMATION CONTACT: Commander Noreen A. Hagerty-Ford, JAGC, U.S. Navy, Office of the Judge Advocate General (Administrative Law), Department of the Navy, 1322 Patterson Ave. SE., Suite 3000, Washington Navy Yard, DC 20374–5066, telephone: 703–614–7408.

SUPPLEMENTARY INFORMATION: The DoN published a rule at 80 FR 68388 on November 4, 2015, to revise 32 CFR part 776, to comport with current policy as stated in JAG Instruction 5803.1 (Series) governing the professional conduct of attorneys practicing under the cognizance and supervision of the Judge Advocate General. The content of § 776.94 is more appropriate as an appendix, and this correction amends the CFR accordingly, redesignating § 776.94 as an appendix to subpart D. In addition, because § 776.94 becomes an appendix to its subpart, DoN is redesignating § 776.95 in the November 4 rule as § 776.94.

Correction

In FR Rule Doc. 2015–26982 appearing on page 68388 in the **Federal Register** of Wednesday, November 4, 2015, the following corrections are made:

■ 1. On page 68390, in the first column, third line, revise ''776.94 Outside Law Practice Questionnaire and Request.'' to read ''Appendix to Subpart D of Part 776—Outside Law Practice Questionnaire and Request.'' and in the seventh line, revise ''776.95 Relations with Non-USG Counsel.'' to read ''776.94 Relations with Non-USG Counsel.'';

■ 2. On page 68408, in the third column, second line, revise ''§ 776.94 of this part'' to read ''appendix to subpart D of part 776'';

■ 3. On page 68408, in the third column, revise the section heading ''§ 776.94 Outside Law Practice Questionnaire and Request.'' to read ''Appendix to Subpart D of Part 776—Outside Law Practice Questionnaire and Request.''; and

■ 4. On page 68409, in the second column under the Subpart E heading, revise ''§ 776.95 Relations with Non-USG Counsel.'' to read ''§ 776.94 Relations with Non-USG Counsel.''.

Dated: November 20, 2015.

N.A. Hagerty-Ford,

Commander,Office of the Judge Advocate General,U.S. Navy, Federal Register Liaison Officer.

[FR Doc. 2015–30190 Filed 11–25–15; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF EDUCATION

34 CFR Parts 600, 602, 603, 668, 682, 685, 686, 690, and 691

[Docket ID ED–2010–OPE–0004]

RIN 1840–AD02

Program Integrity Issues

AGENCY: Office of Postsecondary Education, Department of Education.

ACTION: Final regulations; clarification and additional information.

SUMMARY: On October 29, 2010, the Department of Education published in the **Federal Register** final regulations for improving integrity in the programs authorized under title IV of the Higher