REPORT OF THE SYSTEM RELIABILITY, PLANNING, & SECURITY COMMITTEE

This report provides a summary of the most significant decisions, orders, and rules issued by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) regarding electric reliability section 215 of the Federal Power Act (FPA) and transmission planning from July 1, 2015, through June 30, 2016.*

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I. RELIABILITY GOVERNANCE, STRUCTURE, AND RULES OF PROCEDURE

On November 2, 2015, the FERC conditionally approved revised Regional Delegation Agreements (RDAs) between the North American Electric Reliability Corporation (NERC) and the eight NERC Regional Entities.[1] The RDAs are the agreements through which NERC delegates to the Regional Entities its legal authority under section 215 of the FPA to propose and enforce mandatory Reliability Standards.

The FERC largely accepted NERC's proposed revisions, with several notable exceptions. First, the FERC rejected NERC's proposal to remove from the RDAs reference to the obligation under the NERC Rules of Procedure that NERC audit Regional Entity Compliance Monitoring and Enforcement Program (CMEP) activities at least once every five years and replace it with a general, periodic review of the Regional Entity's performance of all delegation-related activities.[2] The FERC also expressed concern that NERC's proposed amendments "may not grant the Commission sufficient access to NERC reviews (and audits) of the Regional Entities," and ordered NERC to revise the RDAs accordingly so as to grant such access.[3]

Second, the FERC rejected NERC's proposal to revise the term of the RDAs so that the RDAs would apply for an initial five-year term ending on "December 31, 2020 [and] automatically renew[] for one additional five-year term ending on December 31, 2025," unless either party terminated the RDA through written notice no later than December 31, 2019.[4]

Third, the FERC rejected NERC's proposal to require Regional Entities to report information regarding noncompliance with a Reliability Standard, and its eventual disposition by the Regional Entity, in accordance with the confidentiality and disclosure provisions of "guidance that NERC may from time to time develop," in addition to the NERC Rules of Procedure.[5] The FERC expressed concern as to how this "guidance" would supplement the NERC Rules of Procedure, which must be filed with the FERC for approval prior to becoming effective. Accordingly, the FERC directed NERC to revise this language to clarify that any such "guidance" must likewise be filed with the FERC for approval prior to becoming effective.[6]

1. Order Conditionally Approving Revised *Pro Forma* Delegation Agreement And Revised Delegation Agreements With Regional Entities, *North Am. Elec. Reliability Corp.*, 153 F.E.R.C. ¶ 61,135 (2015).

2. *Id.* at P 44.

3. *Id.* at P 49.

4. *Id.* at P 50.

5. *Id.* at P 73.

6. 153 F.E.R.C. ¶ 61,135, at P 73.

NERC submitted a filing in compliance with the FERC's November 2, 2015 order on December 18, 2015, which was subsequently accepted by delegated letter order on March 23, 2016.

II. NERC BUSINESS PLAN, BUDGET, WORKING CAPITAL, AND OPERATING RESERVE POLICY FILINGS

A. Revisions to NERC Working Capital and Operating Reserve Policy

On June 18, 2015, the FERC conditionally approved NERC's request for revisions to its Working Capital and Operating Reserve Policy, which included a new "assessment stabilization reserve [intended] to mitigate year-to-year swings in assessments, which can result from [various] factors, such as application of penalty funds collected, surplus funds . . . from a prior period, . . . or significant but relatively short-term operating or capital spending needs."[7]

However, the FERC did require certain changes. The FERC directed NERC to revise its Reserve Policy to clarify that any extraordinary use of assessment stabilization reserve would be subject to the limits and filing requirements in NERC's Settlement Agreement with the FERC, which stipulates the need for FERC review and approval of certain amounts allocated from the unforeseen contingencies account of operating reserves.[8]

The FERC also found "NERC's request for an exception regarding the use of penalty funds pursuant to NERC Rules of Procedure [section] 1107.4" for the assessment stabilization reserve to be premature.[9] The FERC stated that "such exception is more appropriately addressed on a case-by-case basis, such as in NERC's annual business plan and budget submissions."[10]

B. NERC 2016 Business Plan and Budget

On November 2, 2015, the FERC accepted the 2016 business plans and budgets of NERC, the Regional Entities, and the Western Interconnection Regional Advisory Board (WIRAB), which were originally filed by NERC on August 24, 2015.[11]

The budget proposals included:

- NERC proposed a 0.8% budget increase for 2016 over 2015, with an average assessment increase of 3.2%;
- The total assessments to Load-Serving Entities (LSEs) to support NERC itself would be approximately $57.1 million. NERC also noted that it receives funding from other sources, such as penalty assessments, testing fees, workshop fees, and the proceeding of

7. Order Conditionally Accepting Revisions To Working Capital And Operating Reserve Policy, *North Am. Elec. Reliability Corp*., 151 F.E.R.C. ¶ 61,225 at P 10 (2015).

8. *See* Order Approving Settlement Agreement, *North Am. Elec. Reliability Corp.*, 142 F.E.R.C. ¶ 61,042, 61,217 (2013).

9. 151 F.E.R.C. ¶ 61,225, at P 19.

10. *Id.*

11. Order On 2016 Business Plans and Budgets, *North Am. Elec. Reliability Corp.*, 153 F.E.R.C. ¶ 61,134 (2015).

financing, which would result in total funding of approximately $67.5 million;
- NERC proposed an increase of only 0.2 full-time equivalents (FTEs);
- NERC's consulting and contracting expenses were expected to increase to $3.0 million, mostly due to technology expenses and for Electric Reliability Organization (ERO) Application Development and Support and Applications Enhancement;
- The Region with the highest assessment per kWh (including NERC and Regional costs) was Southwest Power Pool Regional Entity (SPP RE);
- The Region with the lowest assessment per kWh (including NERC and Regional costs) was SERC Reliability Corporation (SERC).

NERC explained that it did not submit a 2016 business plan for Peak Reliability—the Reliability Coordinator for the Western Interconnection—as it had last year because Peak Reliability has developed a new funding arrangement that no longer relied on funding under section 215 of the FPA.[12] NERC explained that Peak Reliability's new funding arrangement would be implemented on a contractual basis through an agreement with funding parties that represent at least 90% of the total net energy for load in the U.S. portion of the Western Interconnection.[13]

In response to NERC's proposed budget filing, on September 15, 2015, the FERC notified NERC that its proposed 2016 business plan and budgets for NERC, the Regional Entities, and WIRAB were deficient.[14] The FERC requested: (1) more justification for "large changes" between the 2015 budgeted amounts and the end-of-year projections for NERC's compliance assurance program area and for WIRAB's proposed 2016 budget; (2) an explanation of why proposed statutory funding for the Cyber Risk Information Sharing Program (CRISP) is increasing from 2015, while overall user-funding for CRISP is decreasing; (3) an explanation for the use of $3.4 million in withheld 2015 Western Electricity Coordinating Council (WECC) penalties; and 4) clarification on an increase in consultant expenses for WECC transmission expansion planning activities.[15] NERC responded to the deficiency letter on September 29, 2015.

The FERC's acceptance of the business plans and budgets on November 2, 2015 authorized NERC to issue billing invoices to fund the fiscal year 2016 operations of those entities.

The FERC urged NERC to be "mindful of its reporting requirements" under a settlement agreement from a prior FERC staff audit.[16] The terms of that settlement agreement require FERC review and approval for transfers of funds of

12. Request for Acceptance of 2016 Business Plans and Budgets of NERC and Regional Entities and for Approval of Proposed Assessments to Fund Budgets, *North Am. Elec. Reliability Corp.*, No. RR15-16-000 at 104 (Aug. 24, 2015).

13. *Id.*

14. *North Am. Elec. Reliability Corp*., Deficiency Notice, No. RR15-16-000 (Sept. 15, 2015) (delegated letter order).

15. *Id.*

16. 153 F.E.R.C. ¶ 61,134, at P 29.

at least $500,000 from one "major activity" to another. The reminder was directed at NERC's prior contention that a reallocation of different full time employees between program areas did not require FERC approval because it did not rise to the level of a "major activity" under the settlement agreement.[17] In response to that assertion, the FERC clarified that it expects NERC to submit for approval any reallocations of budgeted funds and/or expenditure of operating reserves required by NERC's own Reserve Policy and the settlement agreement.[18]

The FERC also addressed comments filed by various utilities urging the FERC to deem ineligible for section 215 funding certain WECC activities, including WECC's Reliability Assessment and Performance Analysis, Situation Awareness, and Transmission Expansion Planning and Policy Committee activities. The FERC disagreed with the commenters and held that the contested activities are within the ambit of those that the FERC has historically recognized as appropriate for statutory funding under section 215 of the FPA. The FERC declared that the reliability assessments prepared by NERC rely on information provided by the Regional Entities, including WECC, and that the challenged WECC activities are instrumental in supporting those reliability assessments. The FERC further clarified that while certain WECC activities such as transmission expansion planning may have other secondary uses, this does not change the fact that the activities are appropriate activities for Reliability Standards development and enforcement. Examples of this include planning activities that could identify reliability problems that could then inform any new or revised Reliability Standards or assist WECC in its assessment of compliance by the Registered Entities in the WECC Region. Following the review of the explanation provided in response to the FERC's deficiency letter, the FERC also explained that in future budgets the WECC should explain how its budget accounts for penalties assessed against WECC.

Lastly, the FERC approved WIRAB's proposed 2016 budget after reviewing responses justifying the overall budget and full-time employee increase from WIRAB's 2015 budget. However, the FERC noted that it is "mindful of WIRAB's expanded activities over the last two years and its increased budget," and that going forward it would carefully review the scope of future WIRAB activities for section 215 funding eligibility.[19]

III. RELIABILITY STANDARDS

A. BAL Standards

On January 29, 2016, NERC submitted a petition for approval of proposed Reliability Standard BAL-002-2 with the FERC.[20] BAL-002-2 is designed to properly identify entities that have the ability to take actions that will ensure reliable operations of the Bulk-Power System by preparing entities to balance resources and demand, and to return the relevant Area Control Error (ACE) to

17. *Id.* at P 27-28.

18. *Id.* at P 29.

19. *Id.* at P 69.

20. *See generally* Petition for Approval of Proposed Reliability Standard BAL-002-2, *North Am. Elec. Reliability Corp.*, No. RM16-7-000 (Jan. 29, 2016).

defined values. On February 12, 2016, NERC submitted clarifying supplemental information to its petition explaining how BAL-002-2 would operate in conjunction with other reliability standards after the retirement of TOP-007-0.[21] NERC also supplemented its petition on March 31, 2016 to provide "clarity regarding the significance of the Most Severe Single Contingency ('MSSC') as the upper bounds for events that qualify as Reportable Balancing Contingency Events ('RBCE') under the Reliability Standard BAL-002-2 and the way in which other Reliability Standards are necessary and appropriate to address events beyond MSSC."[22] On May 19, 2016, the FERC issued a notice of proposed rulemaking that would conditionally approve Reliability Standard BAL-002-2.[23] The notice of proposed rulemaking also proposed to direct NERC to: (1) "modify Reliability Standard BAL-002-2 to address concerns related to the possible extension or delay of the periods for ACE recovery and contingency reserve restoration;" and (2) "address a reliability gap regarding megawatt losses above the most severe single contingency."[24]

On April 20, 2016, NERC submitted a petition for the approval of proposed Reliability Standard BAL-005-1: Balancing Authority Control, which establishes requirements for acquiring data necessary to calculate Reporting ACE.[25] On June 14, 2016, NERC provided supplemental information explaining how Reliability Standard BAL-005-1 supports the proposed retirement of Requirement R15 of Reliability Standard BAL-005-0.2b.[26]

B. FAC Standards

NERC submitted its Petition for Approval of Proposed Reliability Standard FAC-003-4 on March 14, 2016, and requested retirement of the currently-effective Reliability Standard FAC-003-3.[27] "The purpose of proposed Reliability Standard FAC-003-4 is to require entities to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW to reduce the risk of vegetation-related outages that could lead to [c]ascading."[28] The Minimum Vegetation Clearance Distances "reflect[] the minimum distance between vegetation and conductors to prevent a flash-

21. *See generally* Letter from Andrew C. Wills, Associate Counsel, N. Am. Elec. Reliability Corp., to Kimberly D. Bose, Sec., Fed. Energy Reg. Comm'n (Feb. 12, 2016) (Re: Clarifying Supplemental Information for Petition for Approval of BAL-002-2 Docket No. RM16-7-000).

22. Supplemental Information for Petition for Approval of Proposed Reliability Standard BAL-002-2, *North Am. Elec. Reliability Corp.*, No. RM16-7-000 at 1-2 (Mar. 31, 2016).

23. *See generally* Notice of Proposed Rulemaking, 18 CFR Part 40 Disturbance Control Standard-Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 155 F.E.R.C. ¶ 61,180 (2016).

24. *Id.* at P 2.

25. This petition also includes a request for approval of proposed Reliability Standard FAC-001-3, which is explained in Section III.B *infra*. *See generally* Petition for Approval of Proposed Reliability Standards BAL-005-1 and FAC-001-3, *North Am. Elec. Reliability Corp.*, No. RM16-13-000 (Apr. 20, 2016).

26. Supplemental Information for Petition for Approval of Proposed Reliability Standards BAL-005-1 and FAC-001-3, *North Am. Elec. Reliability Corp.*, No. RM16-13-000 (June 20, 2016).

27. Petition for Approval of Proposed Reliability Standard FAC-003-4, *North Am. Elec. Reliability Corp.*, No. RD16-4-000 at 1-2 (Mar. 14, 2016).

28. *Id*. at 2.

over."[29] FAC-003-4 proposes higher and more conservative Minimum Vegetation Clearance Distances to apply a "conservative approach to determining the vegetation clearing distances."[30] On April 26, 2016, the FERC approved NERC's petition in a delegated letter order.[31]

On April 20, 2016, as part of its petition for approval of proposed Reliability Standard BAL-005-1, NERC also requested approval of Reliability Standard FAC-001-3.[32] Proposed Reliability Standard FAC-001-3 includes obligations on Transmission Owners and Generator Owners to confirm that certain facilities are within a Balancing Authority Area's metered boundaries. As proposed, FAC-001-3 establishes facility interconnection requirements. These requirements, which were originally within Reliability Standard BAL-005-0.2b, are more appropriate for inclusion in FAC-001-3.

C. MOD Standards

On November 13, 2015, NERC filed its Petition for Approval of Proposed Reliability Standard MOD-031-2: Demand and Energy Data, "which provides authority for [Bulk-Power] System planners and operators to collect demand, energy, and related data to support reliability studies and assessments, and enumerates the responsibilities and obligations of requestors and respondents of that data."[33] This Reliability Standard modifies two portions of currently-effective Reliability Standard MOD-031-1 to clarify compliance obligations related to providing data to Regional Entities and responding to a request for data subject to confidentiality restrictions.

Specifically, MOD-031-2 modifies Requirement R3 to clarify that Planning Authorities and balancing authorities must provide demand and energy data to their regional entities, upon request, whether or not the planning authority or balancing authority collected that data pursuant to Reliability Standard MOD-031 or through alternative mechanisms. The portion changed under Requirement R3 provides that data will be "collected under Requirement R2," to replace: "data listed under Requirement R1 Parts 1.3 through 1.5 for their area," to the applicable Regional Entity.[34] This change clarifies that the requirement to provide data to a Regional Entity applies broadly to the demand and energy data listed in Requirement R1, whether the data was collected pursuant to a data request under the Reliability Standard or through alternative mechanisms. NERC stated that the modification will provide NERC and the Regional Entities the data necessary to conduct reliability assessments.

29. *Id*.

30. *Id*. at 3.

31. *See generally* Letter from Michael Bardee, Director, Off. Elec. Reliability, to Candice Castaneda, Counsel, N. Am. Elec. Reliability Corp. (Apr. 26, 2016) (Re: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-003-4) [hereinafter April 26 Delegated Letter Order].

32. *See generally* Petition for Approval of Proposed Reliability Standards BAL-005-1 and FAC-001-3, *North Am. Elec. Reliability Corp.*, No. RM16-13-000 (Apr. 20, 2016).

33. Petition for Approval of Proposed Reliability Standard MOD-031-2, *North Am. Elec. Reliability Corp.*, No. RD16-1-000 at 2 (Nov. 13, 2015).

34. *Id.* at 8.

NERC modified Requirement R4 to clarify that an entity "shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; unless providing the requested data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements."[35]

On February 18, 2016, the FERC issued a Letter Order approving NERC's MOD-031-2 petition with an October 1, 2016, effective date for Reliability Standard MOD-031-2.[36]

D. PRC Standards

On November 19, 2015, the FERC issued Order No. 818 approving PRC-010-1, "Undervoltage Load Shedding,"[37] which NERC filed for approval on February 6, 2015.[38] The purpose of this Reliability Standard is to "establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs)."[39] Entities (Distribution Providers, Load Serving Entities, Transmission Operators, and Transmission Owners) will start to evaluate an Entity's UVLS Program's effectiveness prior to it being implemented. Order No. 818 approving PRC-010-1 Reliability Standard consolidates the requirements of currently effective PRC Reliability Standards relating to UVLS Programs. The FERC also approved the retirement of Reliability Standard PRC-022-1.

On June 8, 2015, NERC filed a petition for approval of proposed Reliability Standards PRC-004-5, "Protection System Misoperation Identification and Correction," and PRC-010-2, "Undervoltage Load Shedding."[40] This Reliability Standard is designed to ensure that undervoltage load shedding protective relay misoperations are identified and corrected, and that undervoltage load shedding equipment performance is appropriately evaluated. On December 4, 2015, the FERC approved NERC's filing, and it became effective immediately.[41]

On November 13, 2015, NERC submitted proposed Reliability Standard PRC-005-6 for approval.[42] This Reliability Standard is designed to ensure entities have a program for maintenance of their applicable protection systems, automatic reclosing, and sudden pressure relaying so that they are kept in working order. Along with the petition for approval of PRC-005-6, NERC also filed a motion to

35. *Id.*

36. *See generally* Letter from Michael Bardee, Director, Off. Elec. Reliability, to Shamai Elstein, Senior Counsel, N. Am. Elec. Reliability Corp., (Feb. 18, 2016) (Re: Petition for Approval of Proposed Reliability Standard MOD-031-2).

37. *See generally* Petition for Approval of Proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding), *North Am. Elec. Reliability Corp.*, No. RM15-12-000 (Feb. 6, 2015).

38. *Id.*

39. *Id.* at 3.

40. Petition for Approval of Proposed Reliability Standards PRC-004-5 and PRC-010-2, *North Am. Elec. Reliability Corp.*, No. RD15-5-000 (June 8, 2015).

41. *See generally* Letter from Michael Bardee, Director, Off. Elec. Reliability, to Candice Castaneda, Counsel, N. Am. Elec. Reliability Corp. (Dec. 4, 2015) (Re: Revisions to the Violation Risk Factors for Reliability Standards PRC-004-3, PRC-004-4 and PRC-004-5; approving Reliability Standard PRC- 004-4(i) and PRC-004-5(i)).

42. *See generally* Petition for Approval of Proposed Reliability Standard PRC-005-6, *North Am. Elec. Reliability Corp.*, No. RD16-2-000 (Nov. 13, 2015).

defer implementation to align the implementation of several versions of PRC-005 and to avoid uncertainty due to the patchwork implementation of various requirements.[43] On December 4, 2015, the FERC issued a letter order approving NERC's motion to defer implementation of PRC-005-3, PRC-005-3(i), and PRC-005-4 until after the FERC issues a final order on proposed Reliability Standard PRC-005-6.[44] On December 18, 2015, the FERC approved NERC's uncontested petition and NERC's request for clarification that its data collection obligations will begin in the year following the effective date of PRC-005-6.[45]

On November 19, 2015, the FERC issued Order No. 818 approving NERC's revised definition of "Remedial Action Scheme" as set forth in the NERC Glossary of Terms Used in Reliability Standards, and modifications of specified certain Reliability Standards that incorporate the revised definition. NERC originally submitted the proposed revision and Reliability Standards on February 3, 2015.[46] In its petition, NERC stated that it will "gradually modify all of the NERC Reliability Standards to incorporate the use of only a single term Remedial Action Scheme, starting with revisions to the proposed Reliability Standards."[47] In Order No. 818, the FERC stated that it did not support removing the definition of "Special Protection System" from the NERC Glossary, but that NERC will retire this term once the Reliability Standards are fully updated to reference the revised definition. As an alternative approach, NERC filed a petition for approval of a revised definition of "Special Protection System" to reference the revised definition of "Remedial Action Scheme."[48] NERC stated that this proposal would "complete[] the transition from the term 'Special Protection System' to 'Remedial Action Scheme' that was initiated by NERC in 2014."[49] On June 23, 2016, the FERC issued a letter order approving the revised definition for "Special Protection System."

E. TPL Standards

In Order No. 779, the FERC directed NERC to develop reliability standards to address the potential impact of geomagnetic disturbances (GMDs) on the reliable operation of the Bulk-Power System.[50] Based on this directive, NERC

43. Motion to Defer Implementation and Request for Shortened Response Period and Expedited Action, *North Am. Elec. Reliability Corp.*, Nos. RM14-8-000, RD15-3-000, RM15-9-000 at 1 (Nov. 13, 2015).

44. Letter from Michael Bardee, Director, Off. Elec. Reliability, to Lauren A. Perotti, Counsel, N. Am. Elec. Reliability Corp. (Dec. 4, 2015) (Re: Motion to Defer Implementation and Request for Shortened Response Period and Expedited Action).

45. Letter from Michael Bardee, Director, Off. Elec. Reliability, to Lauren Perotti, Counsel, N. Am. Elec. Reliability Corp. (Dec. 18, 2015) (Re: Petition for Approval of Proposed Reliability Standard PRC-005-6).

46. *See generally* Petition for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards, *North Am. Elec. Reliability Corp.*, No. RM15-13-000 (Feb. 3, 2015).

47. *Id.* at 4.

48. The definition of "Special Protection System" was developed in the same project as proposed Reliability Standard PRC-012-2 (which was approved by the NERC Board of Trustees on May 5, 2016), but in the interest of completing the transition of terms in an expedient manner, NERC submitted the definition for "Special Protection System" in a separate Docket ahead of its petition for approval of proposed PRC-012-2. *See generally* Petition for Approval of the Revised Definition of Special Protection System, *North Am. Elec. Reliability Corp.*, No. RD16-5-000 (Mar. 11, 2016).

49. *Id*. at 3.

50. Order No. 779, *Reliability Standards for Geomagnetic Disturbances*, 143 F.E.R.C. ¶ 61,147 (2013).

developed, proposed, and petitioned the FERC for approval of Reliability Standard TPL-007-1, which relates to transmission system planned performance for GMD events.

NERC's proposed Reliability Standard TPL-007-1 is divided into seven Requirements. Requirement R1 provides that each Planning Coordinator in conjunction with its Transmission Planners shall identify their collective and respective responsibilities for maintaining models and performing studies needed to complete GMD Vulnerability Assessments.[51] Requirement R2 provides that the responsible entities defined under Requirement R1 must maintain system models and geomagnetically-induced current (GIC) system models for the planning area.[52] Requirement R3 provides that the responsible entities must have "criteria for acceptable [s]ystem steady state voltage" performance during the benchmark GMD event.[53] Attachment 1 to Reliability Standard TPL-007-1 provides a defined, one-in-one hundred year event for assessing system performance. The benchmark GMD event uses a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data, scaling factors to account for local geomagnetic latitude and local earth conductivity, and a reference geomagnetic field time series or waveshape. Requirement R4 provides that each responsible entity shall complete a GMD vulnerability assessment every sixty calendar months.[54] Requirement R5 provides that each responsible entity shall provide GIC flow information to be used for transformer thermal impact assessments to each transmission owner and generator owner that owns an applicable bulk electric system transformer in the planning area.[55] Requirement R6 requires each transmission owner and generator owner to conduct a thermal impact assessment for its solely and jointly owned applicable bulk electric system transformers in the planning area where the maximum effective GIC value is 75 A per phase or greater.[56] Finally, Requirement R7 provides that each responsible entity shall develop a corrective action plan if it concludes through a GMD vulnerability assessment that the system does not meet the performance characteristics set forth in Table 1 of Reliability Standard TPL-007-1.[57]

On August 17, 2015, NERC completed its internal appeals processes regarding a complaint filed by the Foundation for Resilient Societies (the Foundation) about Reliability Standard TPL-007-1. The complaint was filed on January 4, 2015, with NERC's Director of Standards pursuant to section 8 of NERC's Standard Process Manual, Appendix 3A to its Rules of Procedure. NERC found that "the Foundation and its objections were afforded fair and equitable treatment during the standard development process for proposed Reliability

51. TPL-007-1-TRANSMISSION SYSTEM PLANNED PERFORMANCE DURING GEOMAGNETIC DISTURBANCES, N. AM. ELEC. RELIABILITY CORP. at 3 (2014).

52. *Id.* at 3.

53. *Id.* at 5.

54. *Id.* at 4.

55. *Id.*

56. TRANSMISSION SYSTEM PLANNED PERFORMANCE DURING GEOMAGNETIC DISTURBANCES, *supra* note 51, at 6-7.

57. *Id.* at 5.

Standard TPL-007-1."[58] The FERC issued a notice seeking comments and reply comments regarding the final decision in the Foundation for Resilient Societies' section 8 appeal.[59]

After the comment periods closed, the FERC convened a technical conference on March 1, 2016, "to clarify issues, share information, and determine appropriate ways to address the issues raised in the NOPR and NOPR comments" in light of various studies on these issues.[60] The technical conference was organized in three panels covering the benchmark GMD event definition, vulnerability assessments, and monitoring and future work. At the outset of the technical conference, FERC's Director of the Office of Electric Reliability noted how contentious this proceeding has been:

> Finally, I want to make one other point. The development of this standard has been an unusually controversial and even confrontational process compared to your usual FERC [or] NERC process. At times the comments filed in recent months with the [FERC] have veered into allegations about bad faith or similar conduct. I just wanted to remind everyone that, while there is uncertainty about many issues in this area, we assume that all of the participants are presenting their views in good faith and that the disagreements here are professional, not personal or ad hominem. We expect the conversation to stay at that level and we expect all of the participants to do the same.[61]

On June 28, 2016, NERC filed supplemental information to update a figure in three of the technical white papers supporting Reliability Standard TPL-007-1 and the related text.[62] Although NERC identified and corrected an error in Figure 1 of the *Screening Criterion for Thermal Impact Assessment* white paper, NERC notes that the standards drafting team determined that the 75 A per phase threshold remains a valid criterion for Requirement R6 and that the reliability standard does not need to be revised. The FERC issued a notice of this supplemental information filing establishing a comment date of July 20, 2016.[63]

F. IRO Standards

On September 16, 2015, NERC filed a petition for approval of Reliability Standards IRO-009-2 and IRO-006-EAST-2.[64] These Reliability Standards were developed in NERC Project 2015-06, which was initiated to implement

58. Letter from Lauren Perotti, Counsel, N. Am. Elec. Reliability Corp., to Kimberly Bose, Sec., Fed. Energy Reg. Comm'n (Aug. 17, 2015) (Re: Conclusion of Standard Process Appeal of the Foundation for Resilient Societies, Inc. regarding Proposed Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events)).

59. *See generally* Notice Setting Comment Period, Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events, *North Am. Elec. Reliability Corp.*, No. RM15-11-000 (Aug. 20, 2015).

60. Supplemental Notice of Agenda and Discussion Topics for Staff Technical Conference, *North Am. Elec. Reliability Corp.*, No. RM15-11-000 at 3 (Feb. 4, 2016).

61. Michael Bardee, Director, Off. Elec. Reliability, Opening Statement *In re* Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events (Mar. 1, 2016).

62. Supplemental Information for Proposed Reliability Standard TPL-007-1, *North Am. Elec. Reliability Corp.*, No. RM15-11-000 at 1 (June 28, 2016).

63. *See generally* Notice of Filing, Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events, *North Am. Elec. Reliability Corp.*, No. RM15-11-000 (June 29, 2016).

64. *See generally* Petition for Approval of Proposed Interconnection Reliability Operations and Coordination Reliability Standards, *North Am. Elec. Reliability Corp.*, No. RD15-7-000 (Sept. 16, 2015).

recommendations for revisions to IRO-009-1 and IRO-006-EAST-1 proposed by the Project 2012-09 Interconnection Reliability Operations Five-Year Review Team.[65]

Reliability Standard IRO-009-2 requires Reliability Coordinators to develop a process to prevent or mitigate exceedances of Interconnection Reliability Operating Limits (IROLs) and to operate to the most limiting IROL and T_V.[66] Reliability Standard IRO-009-2 was designed to consolidate Requirements R1 and R2 of Reliability Standard IRO-009-1, clarify existing requirements, and align the usage of NERC Glossary terms with other Reliability Standards. Reliability Standard IRO-006-EAST-2 is a regional Reliability Standard governing the use of transmission loading relief procedures and congestion management in the Eastern Interconnection. Reliability Standard IRO-006-EAST-2 clarified existing language and retired Requirements R1 and R3 of Reliability Standard IRO-006-EAST-1 as "redundant" or "administrative," consistent with NERC's Paragraph 81 Criteria initiative.[67]

On September 18, 2015, the FERC approved Reliability Standards IRO-009-2 and IRO-006-EAST-1.[68] Pursuant to their respective implementation plans, Reliability Standard IRO-009-2 went into effect on January 1, 2016, and Reliability Standard IRO-006-EAST-2 went into effect on April 1, 2016.

G. Petitions Affecting Multiple Standards Groups

On November 19, 2015, the FERC issued Order No. 817, approving nine proposed TOP and IRO Reliability Standards.[69] The Reliability Standards were filed by NERC for approval on March 18, 2015.[70] NERC submitted supplemental

65. According to the Development History, appended as Exhibit F to the IRO Petition, a separate project (Project 2014-03) recommended the retirement of Reliability Standards IRO-003-2, IRO-004-2, IRO-005-4, IRO-008-1, and IRO-010-1a, leaving only Reliability Standards IRO-009-1 and IRO-006-EAST-1 to be considered under the IRO FYRT recommendations. Petition for Approval of Proposed Interconnection Reliability Operations and Coordination Reliability Standards, *North Am. Elec. Reliability Corp.*, No. RD15-7-000 at 1 (Dec. 4, 2015) [hereinafter Dec. 4 Delegated Letter Order].

66. The term "Interconnection Reliability Operating Limit Tv" is defined in the NERC Glossary as "The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the [i]nterconnection or other Reliability [Coordinator] Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes." N. AM. ELEC. RELIABILITY CORP., SUPPORTING REFERENCE FOR INDENTIFICATION OF INTERCONNECTION RELIABILITY OPERATING LIMITS 4 (Feb. 18, 2005)

67. In Paragraph 81 of the FERC's Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing, the FERC encouraged NERC to identify requirements in Reliability Standards that would likely provide little protection for Bulk-Power System reliability or may be redundant. Consistent with the FERC's guidance, NERC initiated the "P 81 Project" to identify such requirements. Order Accepting With Conditions The Electric Reliability Organization's Petition Requesting Approval Of New Enforcement Mechanisms And Requiring Compliance Filing, *North Am. Elec. Reliability Corp.*, 138 F.E.R.C. ¶ 61,193 at P 81 (2012); *see also* N. AM. ELEC. RELIABILITY CORP., P81 PROJECT TECHNICAL WHITE PAPER 5 (Oct. 23, 2012).

68. Dec. 4 Delegated Letter Order, *supra* note 65.

69. Order No. 817, *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 153 F.E.R.C. ¶ 61,178 (2015).

70. *See generally* Petition for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, *North Am. Elec. Reliability Corp.*, No. RM15-16-000 (Mar. 18, 2015).

information to the original petition to address the removal of load serving entities from the applicability of proposed Reliability Standard TOP-001-3 in light of the FERC's order on NERC's Risk-Based Registration initiative.[71] The proposed TOP and IRO Reliability Standards replace previously effective standards that govern operating responsibilities and improve the delineation of responsibilities between applicable entities. The nine TOP and IRO Reliability Standards approved in Order No. 817 established or revised requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities and operational reliability data. The FERC stated that the revised Reliability Standards improve on the currently-effective standards by (1) "providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities", and (2) "eliminat[ing] gaps and ambiguities in the currently-effective TOP requirements and improv[ing] efficiency."[72] The FERC also directed NERC to make three modifications to the standards within eighteen months of the effective date of Order No. 817:

- Include a requirement that "transmission operator[s] monitor[] . . . non-BES facilities."[73]
- "[S]pecify that data exchange capabilities include redundancy and diverse routing."[74]
- Include a requirement for the testing of "alternate or less frequently used data exchange capability."[75]

On May 26, 2016, NERC filed a petition for approval of proposed Reliability Standards IRO-018-1 and TOP-010-1.[76] NERC states that it developed the proposed Reliability Standards to "improve [r]eal-time situational awareness capabilities and enhance reliable operations by requiring Reliability Coordinators, Transmission Operators, and Balancing Authorities to provide operators with awareness of monitoring and analysis capabilities, including alarm availability, so that operators may take appropriate steps to protect reliability."[77] According to the petition, the proposed Reliability Standards address directives from the FERC in Order No. 693 as well as recommendations from other reliability reports produced by NERC and the FERC.[78]

71. *See generally* Supplemental Information to the Petition for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, *North Am. Elec. Reliability Corp.*, No. RM15-16-000 (May 12, 2015).

72. 153 F.E.R.C. ¶ 61,178, at P 1.

73. *Id.*

74. *Id.*

75. *Id.* at P 19.

76. Petition for Approval of Proposed Reliability Standards IRO-018-1 and TOP-010-1 at 1, *North Am. Elec. Reliability Corp.*, No. RD16-6-000 (May 26, 2016).

77. *Id.* at 3.

78. *Id.* (citing Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, F.E.R.C. Stats. & Regs. ¶ 31,242 at PP 905, 1660, 1875 (2007)); *see generally* N. AM. ELEC. RELIABILITY CORP., REAL-TIME TOOLS SURVEY ANALYSIS AND RECOMMENDATIONS (2008), http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf; FED. ENERGY REG. COMM'N & N. AM. ELEC. RELIABILITY CORP., ARIZONA-SOUTHERN CALIFORNIA OUTAGES ON SEPTEMBER 8,

H. Regional Reliability Standards

On March 23, 2016, NERC and WECC submitted to the FERC a joint petition for the approval of the retirement of the Regional Reliability Standard TOP-007-WECC-1a – System Operating Limits (SOLs).[79] NERC and WECC gave two reasons why the previous Reliability Standards needed to be retired. First, NERC stated that Requirement R1 of TOP-007-WECC-1, which requires transmission operators take immediate action to reduce power flows when actual power flows exceed SOLs for more than thirty minutes, is unnecessary because it is covered adequately by current continent-wide Reliability Standards and the continent-wide Reliability Standards approved by the FERC in Order No. 817 will become effective on April 1, 2017.[80] Second, NERC stated that Requirement R2, which requires that when transmission operators implement the Net Scheduled Interchange (NSI), the "[r]eal-time schedule for the next hour" will not exceed the SOLs, can be replaced because (1) the "Transmission Operator does not control [the] NSI[,]" and (2) "continent-wide Reliability Standards" cover the "coordination of [r]eal-time schedules for the next-hour."[81] NERC requested April 1, 2017, as the effective date of the retirement of Regional Reliability Standard TOP-007-WECC-1a.[82]

On June 9, 2016, NERC and the Northeast Power Coordinating Council (NPCC) jointly petitioned the FERC for the retirement of Regional Reliability Standard PRC-002-NPCC-01 because it has been replaced by continental-wide Reliability Standards.[83] According to the petition, Regional Reliability Standard PRC-002-NPCC-01 was designed to ensure that adequate disturbance data and facilities existed to perform BES analysis.[84] In Order 814, the FERC "approved the continent-wide Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements" which will replace Regional Reliability Standard PRC-002-NPCC-01.[85] NERC and NPCC presented several reasons why the Regional Reliability Standard needs to be retired. First, while "NPCC Regional Reliability Standard PRC-002-NPCC-01 and the continent-wide Reliability Standard PRC-002-2 differ" in their requirements, they "cover the same reliability objectives as the regional standard and are sufficient to ensure that adequate [Sequence of Event Recording] and [Fault Recording] data [are] available to conduct event analysis."[86] Second, "[t]he regional standard requirements will become redundant and unnecessary when continent-wide Reliability Standard PRC-002-2, which contains requirements for the capture of [Dynamic Disturbance Recording] data,

2011: CAUSES AND RECOMMENDATIONS (2012), http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

79. Joint Petition for Approval of the Retirement of the Regional Reliability Standard TOP-007-WECC-1a – System Operating Limits, *North Am. Elec. Reliability Corp.*, No. RM16-10-000 at 3 (Mar. 23, 2016).

80. *Id*. at 5-6.

81. *Id*. at 9-10.

82. *Id*. at 13.

83. Joint Petition for Approval of Retirement of Regional Reliability Standard, *North Am. Elec. Reliability Corp.*, PRC-002-NPCC-01, No. RD16-8-000 at 4 (June 9, 2016).

84. *Id.*at 4.

85. *Id*. at 6.

86. *Id*. at 10.

becomes mandatory and enforceable."[87] Third, "[a]s these continent-wide data specification requirements provide that entities are to provide disturbance monitoring data upon request and establish specific guidelines to ensure the usefulness of the data in analyzing events, the NPCC Regional Reliability Standard requirements for data specifications may be retired with no adverse effect on reliability."[88] Lastly, the continent-wide reliability standards have similar requirements to each other because it requires the "Transmission Owners and Generator Owners to either restore failed SER, FR, or DDR data recording capability within 90 days or implement a Corrective Action Plan that it submits to its Regional Entity."[89] NERC and NPCC requested that the FERC make July 1, 2016, the effective date of the changes.[90]

I. CIP Reliability Standards

1. Version 5 of the CIP Standards

On July 16, 2015, the FERC issued a notice of proposed rulemaking proposing to approve the seven new "CIP Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection)."[91] In addition, the notice of proposed rulemaking proposed to direct NERC to modify Reliability Standard CIP-006-6 to "require protections [of] communication networks" between all BES control centers, and "to direct NERC to develop requirements related to supply chain management for industrial control system hardware, software, and services."[92] On September 21, 2015, NERC commented on the notice of proposed rulemaking responding to several issues raised in the notice of proposed rulemaking and requesting that in the event that the FERC directs NERC to develop a Reliability Standard regarding

87. *Id*. at 11.

88. Joint Petition, *supra* note 83, at 13.

89. *Id*. at 14.

90. *Id*.

91. Notice of Proposed Rulemaking, *Revised Critical Infrastructure Protection Reliability Standards*, 152 F.E.R.C. ¶ 61,054 (2015) (to be codified at 18 C.F.R. pt. 40). As reported in the 2015 System Reliability, Planning, And Security Committee Report, these revised Reliability Standards were submitted to the FERC on February 13, 2015 largely to address directives made by the FERC when it accepted Version 5 of the CIP Reliability Standards in Order No. 791. *See Committee Report on System Reliability, Planning and Security*, 36 ENERGY L.J. 101, 118-19 (2015). Specifically, these changes were intended to:

> (1) remove the "identify, assess, and correct" language from the seventeen requirements in the CIP Version 5 Standards that included such language; (2) "require responsible entities to implement cybersecurity" plans (including cybersecurity awareness, physical security and electronic access controls and incident response plans) for assets containing low impact BES Cyber Systems; (3) require the implementation of protections for "transient" assets; and (4) require the implementation of "security controls for nonprogrammable components of communication networks at Control Centers with high or medium impact BES Cyber Systems." *Id.*

92. 152 F.E.R.C. ¶ 61,054 at 61,335.

supply chain management, NERC be given two years for the development of that Reliability Standard.[93]

On January 21, 2016, the FERC issued Order No. 822 conditionally accepting the Revisions to the Version 5 CIP Reliability Standards.[94] In Order No. 822, the FERC directed NERC to develop modifications (1) to address "transient electronic devices used at Low Impact BES Cyber Systems", (2) to the definition of "Low Impact External Routable Connectivity", and (3) for the protection of communication networks between control centers commensurate with risks to the BES.[95] NERC must also complete a study of the effectiveness of CIP remote access controls, risks posed by remote access-related threats and vulnerabilities, and any appropriate mitigating controls that can be considered. The FERC declined to address the issue of supply chain risk management in this order, electing instead to address the issue at a later time after considering input received in an upcoming January 28, 2016 technical conference that will focus on this issue.[96]

On February 4, 2016, several trade associations requested an extension of the effective date for High and Medium Impact BES Cyber Systems to compliance with the Version 5 CIP Reliability Standards in order to align the effective date with the effective date of the subsequently approved revisions to the Version 5 CIP Reliability Standards approved in the January 28, 2016 order.[97] NERC submitted comments on the trade associations request for extension, arguing that the extension was unneeded.[98] On February 25, 2016, the FERC granted the request for extension and pushed the effective date back from April 1, 2016 to July 1, 2016.[99]

IV. REGISTRATION AND CERTIFICATION

On October 15, 2015, the FERC accepted "NERC's compliance filing to remove the load-serving entity as a functional registration category, and directed NERC to submit an informational filing on the actual effects of this change after it is implemented."[100] The FERC found that "NERC . . . complied with the March 19, 2015 Order with respect to providing additional information justifying the removal of the load-serving entity function and including Reliability Standard PRC-005 as applicable to underfrequency load shedding-only distribution providers."[101]

93. Comments in Response to Notice of Proposed Rulemaking, *Revised Critical Infrastructure Prot. Reliability Standards*, No. RM15-14-000 at 1-2 (Sept. 28, 2016).

94. Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards*, 154 F.E.R.C. ¶ 61,037 (2016).

95. *Id.* at P 3.

96. *Id*.

97. Motion for an Extension of Time and Request for Shortened Comment Period and Expedited Action, *Revised Critical Infrastructure Prot. Reliability Standards*, No. RM15-14-000 at 1 (Feb. 4, 2016).

98. Comments in Response to Motion for Extension of Time, *Revised Critical Infrastructure Prot. Reliability Standards*, No. RM15-14-000 (Feb. 8, 2016).

99. Order Granting Extension of Time, *Revised Critical Infrastructure Prot. Reliability Standards*, 154 F.E.R.C. ¶ 61,137 (2016).

100. Order On Compliance Filing, *North Am. Elec. Reliability Corp.*, 153 F.E.R.C. ¶ 61,024 at P 1 (2015).

101. *Id.* at P 19.

The FERC 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. NERC demonstrates that 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."[102] NERC provided "specific tariff and contract language showing how load-serving entities are obligated to continue to provide information and respond to commands from various entities"; and "described how the load-serving entities will be required to continue to provide the information through their responsibilities as other registered functions."[103] The FERC explained that NERC had alleviated the concern that

> the revision of the distribution provider threshold from [twenty-five] MW to [seventy-five] MW peak load caus[ed] an increase in the deactivation of entities that are currently registered as distribution providers . . . . [through a] technical analysis and mapping document that [showed] other functional entities will take on responsibility for compliance with many Reliability Standards currently assigned to load-serving entities.[104]

Further, the FERC stated: "NERC provides adequate information to show that balancing authorities, planners, and other affected entities will continue to have access to the data to estimate demand and energy forecast for areas where the load-serving entity is deregistered."[105]

While the FERC found that "NERC has adequately addressed its coordination with [North American Energy Standards Board] to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function," the FERC directed NERC "to keep [FERC] staff informed of any developments regarding the appropriate transfer of functions to NAESB."[106]

The FERC also directed NERC to "perform a follow-up analysis to assure that affected transmission operators and balancing authorities remain able to perform reasonably accurate next-day studies."[107] NERC must report to the FERC within 15 months "the extent to which the next-day studies by a representative sample of the affected transmission operators and balancing authorities match or differ from their real-time results and, if there are any significant differences, whether those differences are attributable to the changes authorized here."[108]

V. RELIABILITY COMPLIANCE, ENFORCEMENT, AND NOTICE OF PENALTY

A. The FERC Conditionally Accepts NERC's Reliability Assurance Initiative Compliance Filing

On November 4, 2015, the FERC conditionally accepted two compliance filings made by NERC on May 20, 2015, and July 6, 2015, respectively, in the

102. *Id.* at P 20.
103. *Id.* at P 21.
104. *Id.*
105. 153 F.E.R.C. ¶ 61,024, at P 23.
106. *Id.*
107. *Id.* at P 25.
108. *Id.*

proceeding authorizing the implementation of the Reliability Assurance Initiative (RAI).[109] RAI is multi-year effort among NERC and the Regional Entities designed to transition NERC's CMEP to a "risk-based" approach that focuses CMEP resources on certain activities based on the proportional risk that those activities pose to the reliability of the BES.

NERC filed the May 20, 2015 compliance filing to provide additional detail on "its oversight processes for the RAI program[,]" and the kinds of metrics it will use to track the program's development and success.[110] NERC also provided details on the "self-logging" component of RAI, which allows registered entities with demonstrated effective management practices to self-identify, assess, and mitigate minimal risk instances of noncompliance, and record those instances in an internal log, in lieu of individually self-reporting each instance of noncompliance to the Regional Entity. Regional Entities then periodically review and approve the logs. Once approved, logged issues are usually resolved as compliance exceptions—meaning they are mitigated without formal action by NERC enforcement. NERC submitted an ERO Enterprise self-logging program document in its May 20, 2015, compliance filing, which described the methodologies to be used by Regional Entities when evaluating a registered entity's processes to identify, assess, and correct instances of noncompliance.

NERC made the July 6, 2015 compliance filing to propose definitions for key RAI-related terms, and revisions to the NERC Rules of Procedure in order to: (1) "highlight the types of data NERC uses to identify annual risk elements[;]" (2) "explain that the type and frequency . . . of the compliance monitoring tools appropriate for" a specific entity is based on that entity's specific reliability risk; and (3) "include the principles related to the exercise of enforcement discretion."[111] In addition, NERC proposed revised requirements that Regional Entities include in their CMEP implementation plans "details on the regional risk assessment process and results, Reliability Standards and requirements" identified by regional risk assessments, "and the Regional Entity's Annual Audit Plan."[112]

In its November 4, 2015, order, the FERC accepted NERC's compliance filings, subject to the condition that NERC provide in its annual report on RAI additional information, including: (1) the results of NERC's assessment of the first phase of its oversight of the RAI program; (2) an analysis of self-logging data provided by each Regional Entity; and (3) revised success factors and metrics to evaluate the RAI program.[113] The FERC also conditioned its acceptance of NERC's compliance filings on NERC making an additional compliance filing to modify its Rules of Procedure, including: (1) codifying NERC's proposal that "registered entities submit their self-logs for review by the Regional Entity every three months," with the possibility of adjustment to six months; and (2) incorporating numerous conforming changes and updates to the NERC Rules

109. Order Conditionally Accepting Compliance Filings, *North. Am. Elec. Reliability Corp*., 153 F.E.R.C. ¶ 61,130 at P 1 (2015).

110. Compliance Filing, *North. Am. Elec. Reliability Corp.*, No. RR15-2-001 (May 20, 2016).

111. Compliance Filing and Petition for Approval of Rules of Procedure Revisions, *North. Am. Elec. Reliability Corp.,* No. RR15-2-002 at 1-2 (July 6, 2016).

112. *Id.* at 7.

113. 153 F.E.R.C. ¶ 61,130, at PP 21-22.

of Procedure to better reflect a risk-based CMEP.[114] The FERC also found "that NERC's proposed 12-month data retention period [was] insufficient to allow NERC and the [FERC] to maintain proper oversight of compliance exceptions."[115] The FERC conditioned its acceptance on NERC "requiring registered entities to maintain evidence related to compliance exceptions" for at least eighteen months.[116]

On February 18, 2016, NERC submitted to the FERC its annual CMEP report.[117] On April 14, 2016, the FERC accepted the compliance filing by delegated letter order.[118] On March 3, 2016, NERC submitted to the FERC a filing in compliance with the November 4, 2015 order.[119] On May 4, 2016, the FERC accepted the compliance filing by delegated letter order.[120]

B. Endorsed Guidance

On November 5, 2015, the NERC Board of Trustees approved the compliance guidance policy.[121] The compliance guidance policy establishes the general framework pursuant to which NERC will issue guidance with respect to compliance with NERC Reliability Standards. Compliance Guidance under the Policy is divided into two categories: (i) Implementation Guidance; and (ii) CMEP Practice Guides.

"Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a [particular Reliability] [S]tandard."[122] The examples or approaches are "vetted by industry and endorsed by the ERO Enterprise."[123] "[E]ndorsement of an example means . . . [that] ERO Enterprise CMEP staff will give these examples deference when conducting compliance monitoring activities."[124] Implementation Guidance does not prescribe the only approach to compliance, "but is intended to highlight one or more approaches that would be effective ways" to comply with a Reliability Standard."[125]

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114. *Id.* at P 39.

115. *Id.* at P 37.

116. *Id.*

117. Annual Compliance Monitoring and Enforcement Program Filing, *North. Am. Elec. Reliability Corp.*, No. RR15-2-003 (Feb. 18, 2016).

118. Letter from Michael Bardee, Director, Off. Elec. Reliability, to Sonia Mendonca, Vice President of Enf't & Deputy Gen. Counsel, N. Am. Elec. Reliability Corp. (Apr. 14, 2016) (Re: Annual Compliance Monitoring and Enforcement Program Filing).

119. Compliance Filing and Petition For Approval Of Rules Of Procedure Revisions, *North Am. Elec. Reliability Corp.*, No. RR15-2-004 (Mar. 3, 2016).

120. Letter from Penny Murrell, Director, Div. Elec. Power Reg.-Cent., to Teresina Stasko, N. Am. Elec. Reliability Corp. (May 4, 2015) (Re: Compliance Filing).

121. NORTH AM. ELEC. RELIABILITY CORP., COMPLIANCE GUIDANCE POLICY (Nov. 5, 2016), http://www.nerc.com/pa/comp/Resources/ResourcesDL/Compliance_Guidance_Policy_FINAL_Board_Accepted_Nov_5_2015.pdf.

122. *Id.* at iii.

123. *Id.*

124. *Id.*

125. *Id.* at 1.

CMEP Practice Guides "address how ERO Enterprise CMEP staff executes compliance monitoring and enforcement activities rather than [provide] examples of how to implement [a Reliability] [S]tandard."[126] In contrast to Implementation Guidance, CMEP Practice Guides are "developed solely by the ERO Enterprise to reflect the independent, objective professional judgment of ERO Enterprise CMEP staff."[127]

C. FERC Local Distribution Determination

On December 31, 2015, the FERC issued an order both partially granting and denying Southern California Edison's (SoCal Edison) application for a determination by the FERC of whether or not "certain [115 kV] facilities owned and operated by SoCal Edison are 'used in local distribution of electric energy' pursuant to section 215 of the Federal Power Act."[128] This application arose from SoCal Edison's review of certain 115 kV facilities mandated under FERC Order Nos. 773 and 773-A[129] and desire to maintain the local distribution facility designation for these facilities.[130] The FERC used its seven-factor test set forth in Order 888 to determine what is and is not a local distributed facility.[131] The seven factors are:

> (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems, and rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported onto some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and (7) local distribution systems will be of reduced voltage.[132]

These seven factors represent a starting point for the FERC, which also considers other criteria on a case-by-case basis.[133] The FERC found that "SoCal Edison's 115 kV facilities are used in local distribution with the exception of the protection systems and the segments of the associated transmission lines located within the yards of the Control and Inyokern's 115 kV substations located in SoCal Edison's North of Lugo system."[134] In applying the test, the FERC found that most of the 115 kV facilities are a part of the local distribution system and not the

126. NORTH AM. ELEC. RELIABILITY CORP., *supra* note 121, at iii.

127. *Id.* at 4.

128. Order On Local Distribution Determination, *Southern Cal. Edison Co.*, 153 F.E.R.C. 61,384 P 1 (2015).

129. Order No. 773, *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 141 F.E.R.C. ¶ 61,236 (2012); Order No. 773-A, *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 143 F.E.R.C. ¶ 61,053 (2013).

130. Application of Southern California Edison Company for Factual Determination that the Indicated 115 kV Facilities are used in Local Distribution, *Southern Cal. Edison Co.*, No. RC15-1-000 at 2 (Apr. 15, 2015).

131. 153 F.E.R.C. 61,384, at P 3.

132. *Id*. at P 4 (citing Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. Stats. & Regs. ¶ 31,036 (1996)).

133. 153 F.E.R.C. ¶ 61,384, at P 4.

134. *Id*. at P 18.

transmission system.[135] However, the FERC found that while the Control and Inyokern 115 kV substations meet the criteria of the seven-factor test for local distribution facilities, those facilities are still part of the transmission system because of additional factors.[136] The FERC found that misoperation of these facilities would cause the "loss of multiple bulk electric system transmission lines" because "multiple bulk electric system lines would have to be taken out of service to isolate a fault on the distribution line if the distribution line protection fails."[137] The FERC concluded that, under the totality of the circumstances, the "segments of the transmission lines associated with the individual protection systems at the Control and Inyokern substations are not 'used in local distribution.'"[138] The FERC noted that that SoCal Edison has to obtain a ruling from NERC to determine whether or not the facilities are a part of the Bulk Electric System under NERC's definition and exemptions.[139]

VI. RELIABILITY REPORTS AND ASSESSMENTS

A. NERC Report On Potential Reliability Risks Due to Increased Natural Gas Dependence

On May 24, 2016, NERC issued a Short-Term Special Assessment addressing the risks associated with high-penetration of Natural Gas-Fired Generation. This report follows the 2011 and 2013 reports on gas-electric interdependencies.[140] In the May 2016 Report, NERC concluded that while progress has occurred in the last five years to improve coordination amongst the key actors in the natural gas space, new risks exist and progress must continue to maintain reliability.

NERC examined the resource mix for areas with natural gas generation penetration greater than 40%. These include the Independent System Operator of New England (ISO-NE), New York Independent System Operator (NYISO), Electric Reliability Council of Texas (ERCOT), and WECC-CA/MX regions. NERC analyzed the amount of peak load expected to be served by gas-fired generation during the next eighteen to twenty-four months. Using NERC GADS7 "performance data [and] existing industry analysis," NERC then developed assumptions on "potential forced outages and unit unavailability."[141] This process created extreme cases that NERC evaluated to understand the risk to the Bulk-Power System.

This study found that "areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply

135. *Id.* at PP 20-28.

136. *Id.* at P 33.

137. *Id*. at P 34.

138. 153 F.E.R.C. ¶ 61,384, at P 35.

139. *Id.* at P 36 n.42.

140. NORTH AM. ELEC. RELIABILITY CORP., SHORT-TERM SPECIAL ASSESSMENT: OPERATIONAL RISK ASSESSMENT WITH HIGH PENETRATION OF NATURAL GAS-FIRED GENERATION (May 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf.

141. *Id.* at vi.

unavailability."[142] The greater the reliance on a single source of natural gas-fired generation, the greater the "localized risks to reliability."[143] Furthermore, the study found that extreme winter conditions are not a prerequisite for issues with natural gas fired generation.[144] The recent Southern California outages and disruption to storage facilities are examples of extreme summer conditions causing natural gas generation disturbances. Lastly, the study found that "[h]igh levels of coordination between natural gas and electric system[s]" resulted in much more resilience.[145]

NERC's recommendations revolve around increased coordination. The study recommended that planners and operators continue to expect and develop strategies for extreme weather events that will result in potential gas-fired generator outages.[146] The study also recommended that planners and operators organize to "establish guidelines for future reliability assessments to evaluate both short-term and long-term fuel availability, generation operational characteristics, and other related risks."[147] The study recommended more "coordination strategies to address potential fuel supply interruptions due to unforeseeable conditions."[148] To help facilitate these recommendations NERC and WECC pledged to work with entities and conduct a joint meeting to "identify high-level reliability risks associated with the loss of the Aliso Canyon storage facility [in Southern California] and develop mitigat[ion] strategies" with expanded applicability.[149]

B. NERC Report on Reliability Performance, Weather Resiliency and Human Error

On May 17, 2016, NERC issued its annual *State of Reliability Report*.[150] The report focused on the reliability performance of the Bulk-Power System over the past year, summarizes the results of activities taken to ensure reliability, and identifies areas for improvement. NERC concluded that the Bulk-Power System performed well in 2015.[151]

To determine the performance of the Bulk-Power System, NERC conducted a system performance assessment that involved gathering data from a host of sources. Using early analysis of system performance data, NERC initiated a number of risk mitigation activities and analyzed the effect of those efforts. The organization also utilized system performance data provided by the industry, including the information data systems for transmission, demand response, generation, and protection systems. Further, NERC gathered specific event

142. *Id.*
143. *Id.*
144. *Id.*
145. NORTH AM. ELEC. RELIABILITY CORP., *supra* note 140, at vi.
146. *Id.*
147. *Id.*
148. *Id.* at vii.
149. *Id.*
150. NORTH AM. ELEC. RELIABILITY CORP., STATE OF RELIABILITY 2016 (May 2016), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf.
151. *Id.* at iv.

information voluntarily provided by industry actors. Trend enforcement data also factored into NERC's system performance assessment. These data are comprised of two metrics, a risk metric based on quarterly violations determined to pose a serious risk to the Bulk-Power System and an impact metric based on quarterly non-compliances with reliability impacts.[152] NERC compiled data through December 2015.

After conducting its assessment, NERC determined that the Bulk-Power System provided an "Adequate Level of Reliability (ALR) for the year."[153] This means that for 2015, the Bulk-Power System achieved the listed Reliability Performance Objectives enumerated in NERC's 2013 *Informational Filing on the Definition of "Adequate Level of Reliability."* The objectives included stable Bulk-Power System "frequency and voltage within predefined ranges and no instability, uncontrolled separation, cascading loss of elements, . . . or voltage collapse."[154]

The assessment found that "[i]nstances of protection system misoperations have decreased" by 10%, the Bulk-Power System is more resilient to severe weather events, and that "[t]ransmission line outages caused by human error" continue to fall.[155] NERC also determined that 2015 had "[n]o load loss caused by cybersecurity events," that "[f]requency and voltage remained stable," and that there has been a greater understanding of the grid, which has resulted in simulations that more accurately measure reliability risks.[156]

C. FERC, NERC Report on Grid Restoration and Recovery

On January 29, 2016, NERC and the FERC published a joint-staff report on restoration and recovery plans.[157] The report includes a sample of nine registered entities with important Bulk-Power System responsibilities. The report evaluated the restoration, response and recovery plans of each participant, which included "reliability coordinator-approved restoration plans, procedures for deploying blackstart resources, steady state and dynamic simulations testing the effectiveness of the plans, and cyber security incident response plans and recovery plans for critical cyber assets."[158]

The joint staff also gathered data from employees at the sample entities regarding their experiences with these response plans. The report evaluated the plans at various stages, but the joint staff emphasized restoration, "cyber security incident response" and critical cyber asset recovery.[159]

The report concluded that system restoration plans are generally "thorough and highly-detailed" and comprehensively cover restoration, cyber security

152. *Id.*

153. *Id.*

154. *Id.* at v.

155. NORTH AM. ELEC. RELIABILITY CORP., *supra* note 150, at v.

156. *Id.*

157. FED. ENERGY REG. COMM'N & NORTH AM. ELEC. RELIABILITY CORP., REPORT ON THE FERC-NERC-REGIONAL ENTITY JOINT REVIEW OF RESTORATION AND RECOVERY PLANS (Jan. 29, 2016), http://www.ferc.gov/legal/staff-reports/2016/01-29-16-FERC-NERC-Report.pdf.

158. *Id.* at i.

159. *Id.* at ii.

incident response and critical cyber asset recovery.[160] However, the report identified areas of improvement in both system restoration planning and cyber incident responses.

The system restoration planning recommendations include both changes to the plans and new studies and coordination efforts to achieve better understanding when creating the plans. The report found that plans are not entirely clear on what type of system changes trigger automatic updates to restoration plans and that plans do not address the efficacy testing in the wake of system changes that may necessitate a plan change. The joint staff also recommended that studies be conducted on access and efficacy of restoration plans if Supervisory Control and Data Acquisition (SCADA) and other data sources are lost, the availability of blackstart resources, and the use of direct current facilities in the restoration process. The report encouraged coordination between entities that have experienced a widespread outage and those that have not as it provides another data point in determining the viability of a restoration plan.

Regarding cyber incident response plans, the report suggested that plans should include more details about the characteristics of events that require response and reporting. The report recommended greater "[u]se of technical expertise and advanced tools" to improve both monitoring and responses.[161] The report cautioned that excessive use of these tools may result in monitoring and response processes that are unnecessarily burdensome. The report also suggested independent review of the response plans and drills.

The report found that many plans go beyond what is required under the Reliability Standards and indicated general approval of the recent efforts made to enhance the restoration and recovery plans.

D. NERC Report on Essential Reliability Services and Reserve Margins

On January 27, 2016, NERC issued a report to ensure that regulators and officers take stock of reliability considerations when designing state implementation plans to meet requirements under the Clean Power Plan.[162]

In the report, NERC explained that coordination across businesses, states, and regions is necessary to maintain reliability because states share electric system connections and a state implementation plans in one state may have drastic impacts on reliability in a neighboring state. NERC also noted that regulators must take into account the "interconnection requirements, market mechanisms, [and] other reliability requirements" to allow for electric systems to adapt to large amounts of "variable and/or distributed energy resources."[163] Additionally, NERC explained that regulators must account for energy infrastructure developments and properly time the integration of those resources into the existing generation mix. Retirements may happen quickly, but uncertainty exists in the timing for new

160. *Id.*

161. *Id.* at vi.

162. NORTH AM. ELEC. RELIABILITY CORP., RELIABILITY CONSIDERATIONS FOR CLEAN POWER PLAN DEVELOPMENT at v (Jan. 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf.

163. *Id.* at vi.

bulk-power system infrastructure so state implementation plans may need adjustment based on this uncertainty.

NERC also suggested that state implementation plans take into account imports and exports both now and in the future. If foreign resources are expected to comprise part of the compliance measures a state takes in its state implementation plan, it must determine the transmission capability and reliability of that power. Further complicating this is the fact that generation mix will shift. Certain plants will be run at different outputs, complicating how regulators are able to both meet the requirements of the Clean Power Plan while ensuring reliability.

E. NERC Report on Frequency Support, Ramping Capability and Voltage Support Essential to Reliability Services

In 2014, the NERC Planning and Operating Committees created the Essential Reliability Services Task Force. On December 17, 2015, the task force issued a report to address the changing generation mix to the Bulk-Power System.[164] In the report, the task force explained that environmental regulations have caused coal-fired generation retirements while renewable portfolio standards have led to the increase in wind and solar generation.[165] The purpose of the report was to help industry participants understand and prepare for the increase in variable energy resources to minimize impacts on reliability.

The report is based on discussions with system operators, system planners, and industry experts. The task force reviewed disruptive technologies in the renewable energy sector and discussed with entities that have "experienc[ed] significant transitions in generation resource mix."[166] The task force concluded that a greater effort must be made to account for the impacts of these generation shifts in system planning, system operations and in energy policy-making.

The task force's recommendations track three areas of reliability: frequency, ramping, and voltage, largely suggesting more information gathering for use in studies and predictive models. The task force suggested research into instances of "minimal synchronous inertial response" for the past year and three years into the future.[167] For each of these years, the frequency deviation following the largest contingency of the interconnection needs to be collected along with the minimum frequency point at each interconnection. Further, each interconnection should have all aspects of the response following a contingency event measured. The task force also recommended that each balancing authority calculate the maximum one-hour and three-hour up and down demand ramps using one-minute data.

The task force stated that entities should measure and tracking reactive capability in greater detail in order to address potential voltage issues. Further, system events that suggest stressed reactive capability or degraded voltage profiles

164. NORTH AM. ELEC. RELIABILITY CORP., ESSENTIAL RELIABILITY SERVICES TASK FORCE MEASURES FRAMEWORK REPORT at v (Dec. 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

165. *Id.* at iv.

166. *Id.*

167. *Id.* at x.

should be studied. Entities should measure system strength based on calculating short circuit ratios for sub-areas in the system.

At a more general level, the task force recommended better monitoring and more data collection efforts. The task force also suggested more collaboration amongst entities, which should allow for better forecasting of the effects of variable generation.

F. NERC Report on April 2015 Washington, D.C. Area Low-Voltage Disturbance Event

On September 16, 2015, NERC issued a report analyzing the system disturbance that occurred in Washington, D.C. on April 7, 2015.[168] This report was prepared jointly with ReliabilityFirst and contained analysis on the cause, remediation, and lessons learned from the event.

The event, lasting only fifty-eight seconds, occurred on a circuit owned by Potomac Electric Power Company (PEPCO) and resulted in 532 MW of lost customer load. NERC found that no foul weather or nefarious actions were involved in the disturbance; rather, it was a result of a failure of a piece of equipment and the corresponding protection system.[169] The short circuit was due to the failure of a surge arrester on the 230 kV circuit at the Ryceville substation. Surge arrestors "protect the insulation and conductors of the system from . . . extremely high voltage."[170]

The short circuit caused the circuit breakers to trip; however, an error occurred while reclosing. A breaker failed to reopen, sustaining the fault, which resulted in a de-energizing of the entire Chalk Point substation. The post-incident analysis discovered two protection system failures that occurred independently. The first was due to a loose connection between the auxiliary retail coil cutoff trip and the breaker contract string. The second was an "intermittent electrical discontinuity in the auxiliary relay coil circuit, which occurred when the chalk point breaker reclosed into fault."[171]

PEPCO modified the circuit design in the wake of the event. The analysis team recommended that PEPCO evaluate the design of its protection schemes and that NERC create guidelines on backup, time-delayed ground overcurrent and phase protection. The team was surprised that the impacts of the disturbance disproportionately affected load that was separated from the electrical system and recommended further study of load models and behavior of loads in response to abnormal conditions.

VII. GRID SECURITY AND CRITICAL ASSET SECURITY

The Electricity Information Sharing and Analysis Center (E-ISAC, formerly the ES-ISAC) is one of several industry information sharing and analysis centers

168. NORTH AM. ELEC. RELIABILITY CORP., WASHINGTON, D.C., AREA LOW-VOLTAGE DISTURBANCE EVENT OF APRIL 7, 2015 (Sept. 2015), http://www.nerc.com/pa/rrm/April%202015%20Washington%20DC%20Area%20LowVoltage%20Disturban/Washington_DC_Area_Low-Voltage_Disturbance_Event_of_April_7_2015_final.pdf.

169. *Id.* at v.

170. *Id.*

171. *Id.*

established pursuant to a presidential directive established in 1998.[172] The E-ISAC, in collaboration with the Department of Energy and the Electricity Subsector Coordinating Council, serves as the primary security communications channel for the electricity subsector and enhances the subsector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents. On March 18, 2016, the E-ISAC and the SANS Institute jointly issued a white paper analyzing and presenting a defense use case regarding the recent analysis of the "cyber attack on the Ukrainian power grid."[173] The E-ISAC also developed several outreach and education materials. In May 2016, E-ISAC developed a brochure describing its products and services.[174] In June 2016, E-ISAC issued a white paper, "Understanding Your E-ISAC," outlining the organization, membership, the benefits of information sharing and analysis, and other aspects of E-ISAC activities.[175] In 2015, the Electricity Subsector Coordinating Council conducted a strategic review of the E-ISAC regarding its activities and resource requirements, including the CRISP; the Electricity Subsector Coordinating Council presented its recommendations in June 2015, which are included in the NERC 2016 Business Plan and Budget.

VIII. OTHER FERC RELIABILITY INITIATIVES

A. Essential Reliability Services

On November 19, 2015, the FERC issued a notice of proposed rulemaking proposing to revise the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G to the *pro forma* LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA) "to eliminate the exemptions for wind generators from the requirement to provide reactive power."[176] On January 27, 2016, NERC submitted comments to the FERC.[177] NERC's comments supported the FERC's proposal to eliminate the exemptions for wind generation and to require all non-synchronous generation resources to provide reactive power. On June 16, 2016, the FERC issued Order No. 827 revising the *pro forma* LGIA and *pro forma* SGIA and eliminating the exemption for wind generators.[178] Order No. 827 requires "newly interconnecting non-synchronous generators that have not yet

172. Presidential Decision Directive/NSC-63 (May 22, 1998), http:// www.fas.org/irp/offdocs/pdd/pdd-63.pdf (Re: on Critical Infrastructure Protection).

173. ELECTRICITY INFO. SHARING & ANALYSIS CTR. & SANS INST., ANALYSIS OF THE CYBER ATTACK ON THE UKRAINIAN POWER GRID: DEFENSE USE CASE at iii (Mar. 18 2016), http://www.nerc.com/pa/CI/ESISAC/Documents/E-ISAC_SANS_Ukraine_DUC_18Mar2016.pdf.

174. ELECTRICITY INFO. SHARING & ANALYSIS CTR., PRODUCTS AND SERVICES (2016), http://www.nerc.com/pa/CI/ESISAC/Documents/E-ISAC%20Brochure.pdf.

175. ELEC. INFO. SHARING & ANALYSIS CTR., UNDERSTANDING YOUR E-ISAC (June 2016), http://www.nerc.com/pa/CI/ESISAC/Documents/Understanding%20Your%20E-ISAC_June%2028%202016_FINAL.PDF.

176. Notice of Proposed Rulemaking, *Reactive Power Requirements for Non-Synchronous Generation*, 153 F.E.R.C. ¶ 61,175 (2015).

177. Comments in Response to Notice of Proposed Rulemaking, *Reactive Power Requirements for Non-Synchronous Generation*, No. RM16-1-000 (Jan. 27, 2016).

178. Order No. 827, *Reactive Power Requirements for Non-Synchronous Generation*, F.E.R.C. Stats. & Regs. ¶ 31,385 (2016) (to be codified at 18 C.F.R. pt. 35).

executed a Facilities Study Agreement as of the effective date of [Order 827] . . . to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation."[179]

On March 17, 2016, the FERC issued a notice of proposed rulemaking proposing to modify the *pro forma* SGIA to require new interconnection customers to ensure the frequency ride through capability and the voltage ride through capability of small generating facilities.[180] Additionally, the notice of proposed rulemaking proposed to "require a small generating facility not to disconnect automatically or instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition."[181] The FERC reasoned that because large generating facilities are required to have this capability, it would be unduly discriminatory not to also impose these requirements on small generating facilities.[182] The notice of proposed rulemaking proposed to require transmission providers to coordinate protective equipment settings with automatic load shedding programs.[183] On May 23, 2016, NERC submitted comments to the FERC.[184] NERC's comments supported the FERC's proposed rule and noted that consistent application of "frequency and voltage ride through requirements under the [*pro forma*] SGIA and [*pro forma*] LGIA would be consistent with NERC reliability assessments related to the transforming resource mix."[185]

On February 18, 2016, the FERC issued a notice of inquiry seeking comment "on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response."[186] The FERC noted that the changing resource mix along with the retirement of baseload synchronous units could reduce the net amount of frequency response generation online and present reliability challenges for system operators.[187] The FERC asked for comments regarding whether amendments to the *pro forma* LGIA and *pro forma* SGIA are "warranted to require all new generation resources to have frequency response capabilities as a precondition of interconnection,"[188] and "whether primary frequency response requirements" should be imposed on existing generation resources, and procurement and compensation mechanisms for primary frequency

179. *Id.* at P 1.

180. Notice of Proposed Rulemaking, *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 154 F.E.R.C. ¶ 61,222 (2016) (to be codified at 18 CFR pt. 35).

181. *Id.* at P 11.

182. *Id.* at P 8.

183. *Id.* at P 12.

184. Comments in Response to Notice of Proposed Rulemaking, *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, No. RM16-8-000 (May 23, 2016).

185. *Id.* at 3.

186. Notice of Inquiry, *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, 154 F.E.R.C. ¶ 61,117 at P 1 (2016).

187. *Id.* at PP 8, 14.

188. *Id*. at P 2.

response.[189] On April 25, 2016, NERC submitted comments to the FERC.[190] NERC's comments agreed that "adequate frequency response capability [must be] present in the evolving resource mix to ensure reliability and support system restoration upon loss of resources or load" notes that the suggested changes could support frequency response.[191] NERC also provided several factors for the FERC's consideration as it evaluates the potential mechanisms proposed in the notice of inquiry to ensure adequate frequency response.[192]

B. FERC Collection of Reliability Data

On September 17, 2015, the FERC issued a notice of proposed rulemaking proposing to amend its regulations to require NERC to provide the FERC and its staff with non-public and ongoing access to three non-public databases regarding U.S. facilities.[193] The databases are the Transmission Availability Data System, the Generating Availability Data System and the protection system misoperations database. The FERC received thirteen comments.

On June 16, 2016, the FERC issued Order No. 824 amending Title 18, section 39.11 of the Code of Federal Regulations to add paragraph (c).[194] Order No. 824 requires the ERO to make the Transmission Availability Data System, the Generator Availability Data System and the protection system misoperations databases available to the FERC on a non-public and ongoing basis and limited to data regarding U.S. facilities that are not voluntarily submitted to the Electric Reliability Organization. On July 7, 2016, the FERC issued an order clarifying the effective date and compliance date of Order No. 824.[195] Order No. 824 became effective when it was published in the Federal Register, but compliance is contingent on the final rule in FERC Docket No. RM16-15-000. In that proceeding, the FERC has proposed to promulgate regulations required under the Fixing America's Surface Transportation Act which will change the FERC's policy regarding designation, protection, and sharing of sensitive and confidential energy sector infrastructure information.[196]

189. *Id*.

190. Comments in Response to Notice of Inquiry, *Essential Reliability Services and the Evolving Bulk-Power-System—Primary Frequency Response*, No. RM16-6-000 (Apr. 25, 2016).

191. *Id.* at 21.

192. *Id*. at 16-17.

193. Notice of Proposed Rulemaking, *Availability of Certain North American Reliability Corporation Databases to the Commission*, 152 F.E.R.C. ¶ 61,208 at PP 1-2 (2015) (to be codified at 18 C.F.R. pt. 39).

194. Order No. 824, A*vailability of Certain North American Reliability Corporation Databases to the Commission*, F.E.R.C. Stats. & Regs. ¶ 31,383 (2016) (to be codified at 18 C.F.R. § 39.11).

195. Order Clarifying Effective Date and Compliance Date, *Availability of Certain North American Reliability Corporation Databases to the Commission*, 156 F.E.R.C. ¶ 61,107 (2016).

196. Notice of Proposed Rulemaking, *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, 155 F.E.R.C. ¶ 61,278 (2016).

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