REPORT OF THE SYSTEM RELIABILITY, PLANNING, AND SECURITY COMMITTEE

This report summarizes 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, 2017, through June 30, 2018.*

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I. RELIABILITY GOVERNANCE, STRUCTURE, AND RULES OF PROCEDURE (ROP)

A. Order Granting Approvals In Connection With The Dissolution Of The Southwest Power Pool Regional Entity

On March 5, 2018, the North American Electric Reliability Corporation (NERC), Midwest Reliability Organization (MRO), and SERC Reliability Corporation (SERC) (collectively, Petitioners) submitted a joint petition with the FERC requesting approvals in association "with the dissolution of the Southwest Power Pool Regional Entity (SPP RE)."[1] The joint petition sought the following approvals from the FERC: (1) "the termination of the Amended and Restated Delegation Agreement (Regional Delegation Agreement) between NERC" and SPP RE; (2) a proposal of transfers of registered entities within the SPP RE footprint to MRO and SERC by July 1, 2018; and (3) "revisions to the Regional Delegation Agreements between NERC and MRO and between NERC and SERC to reflect the changed geographic footprints of MRO and SERC."[2]

On July 20, 2006, the FERC identified NERC as the Electric Reliability Organization (ERO) and also "accepted NERC's "*pro forma* delegation of certain ERO functions."[3] NERC entered into eight separate Regional Delegation Agreements with Regional Entities including SPP RE, MRO and SERC to delegate certain ERO functions.[4]

In July 2017, NERC and Southwest Power Pool (SPP) entered into a Termination Agreement that set out the dissolution of SPP RE and the responsibilities

1. *North Am. Elec. Reliability Corp., Midwest Reliability Org., & SERC Reliability Corp.*, 163 F.E.R.C. ¶ 61,094, at P 1 (2018).
2. *Id*.
3. *Id.* at P 3.
4. *Id*.

of each party.[5] Per the Termination Agreement, NERC was responsible for identifying the Regional Entities that would receive the registered entities currently within the SPP RE footprint.[6] SPP was responsible for providing documentation to the identified Regional Entities, providing a report to NERC on the re-allocation of monies, and submitting a reconciliation report of "SPP RE's actual expenses with its budgeted 2018 expenses."[7]

NERC's criteria to maintain effectiveness and efficiency in the ERO Enterprise in determining where the registered entities will transfer was the requirements to stay within common geographical boundaries and maintain the same interconnections as the entities in SPP RE.[8] The two Regional Entities identified were MRO and SERC.[9] According to its joint petition, NERC does not expect any gaps when transfer occurs and the only proposed changes to the existing Regional Delegation Agreements between NERC and MRO and between NERC and SERC is to the geographic boundaries.[10]

On May 4, 2018, the FERC granted "the requested approvals to reflect the dissolution of the SPP RE and the transfer of its registered entities to MRO and SERC."[11] The FERC found that NERC appropriately applied the criteria in section 1208 of NERC's Rules of Procedure and applicable FERC precedent for determining MRO and SERC as the correct Regional Entities to transfer the registered entities within SPP RE.[12] Further, the FERC found that NERC appropriately mitigated the risk of material gaps in oversight of compliance and enforcement activities.[13] Finally, the FERC approved NERC's role as the Compliance Enforcement Authority for the SPP Reliability Coordinator function for two years to facilitate the transition.[14]

B. Petition of NERC for Approval of Revised SERC Regional Reliability Standard Development Procedure

On February 12, 2018, the NERC filed a petition seeking approval of revised SERC Reliability Corporation Regional Reliability Standards Development Procedure (RSDP).[15] SERC revised its RSDP to account for revisions to the NERC-SERC Delegation Agreement, revised its RSDP in several places to align with NERC documents, revised the names of certain SERC committee titles and process roles to reflect the current SERC committee and organization structure, added a Roles and Responsibilities chart as Appendix H, added an Errata section, and

5. *Id.* at P 4.
6. 163 F.E.R.C. ¶ 61,094 at P 5.
7. *Id.*
8. *Id.* at P 8.
9. *Id.*
10. *Id.* at PP 10-11.
11. 163 F.E.R.C. ¶ 61,094 at P 16.
12. *Id.* at P 17.
13. *Id.*
14. *Id.* at P 12.
15. Petition of NERC for Approval of Amendments to the SERC Reliability Corporation Regional Reliability Standard Development Procedure, *North Am. Elec. Reliability Corp*., FERC Docket No. RR18-2-000 (Feb. 12, 2018).

made a number of non-substantive revisions to improve language and format.[16] These changes will create a more consistent format and appearance with other SERC documents. The FERC issued its Letter Approving the SERC RSDP on March 31, 2018.[17]

C. Petition of NERC for Approval of Proposed Revisions to Appendix 3D to the Rules of Procedure

On November 21, 2017, the NERC filed a petition seeking approval of proposed revisions to Appendix 3D (Registered Ballot Body Criteria) of the NERC Rules of Procedure.[18] NERC stated the proposed revisions is "to help ensure that the votes of Independent System Operators and Regional Transmission Organizations are appropriately represented in Segment 2 of NERC's Registered Ballot Body for voting on NERC Reliability Standards."[19] Segment 2 of NERC's Registered Ballot Body is designed to represent only Independent System Operators and Regional Transmission Organizations.[20] Currently, other individuals and entities, such as consultants and vendors, can participate and have substantial impact on the voting outcome for Segment 2.[21] The proposed revision would make Segment 2 voting exclusive to only Independent System Operators and Regional Transmission Organizations.[22] On March 8, 2018, the FERC issued a letter order approving the proposed revisions to Appendix 3D.[23]

II. NERC BUSINESS PLAN AND BUDGET

A. Order Accepting 2018 Business Plans and Budgets

On August 23, 2017, the NERC filed a request for acceptance of its 2018 Business Plans and Budget Filing for itself, each Regional Entity, and the Western Interconnection Regional Advisory Board (WIRAB).[24] On November 1, 2017, the FERC issued an order accepting the 2018 business plans and budgets for NERC, each Regional Entity, and WIRAB.[25]

In its filing, NERC stated that the assessment for the ERO Enterprise "(i.e., NERC, the Regional Entities, and WIRAB) for 2018 allocable to the United States

16. *Id.* at 2-3.

17. Letter Order Approving Revised SERC Reliability Corporation Regional Reliability Standard Development Procedure, *North Am. Elec. Reliability Corp.*, FERC Docket No. RR18-2-000 (Mar. 31, 2018).

18. Petition of the NERC for Approval of Proposed Revisions to Appendix 3D to the Rules of Procedure, *North. Am. Elec. Reliability Corp*., FERC Docket No. RD18-1-000 (Nov. 21, 2017).

19. *Id.*

20. *Id.* at 3.

21. *Id.*

22. *Id.* at 4.

23. Letter Order, Joint Petition for Approval of Proposed Revisions to the Rules of Procedure, *North Am. Elec. Reliability Corp.*, FERC Docket No. RR18-1-000 (Mar. 8, 2018).

24. NERC Request for Acceptance of 2018 Business Plans and Budgets of NERC and Regional Entities and for Approval of Proposed Assessments to Fund Budgets, *North Am. Elec. Reliability Corp.*, FERC Docket No. RR17-7000 (Aug. 23, 2017).

25. Order Accepting 2018 Business Plans and Budgets, *North Am. Elec. Reliability Corp.*, 161 F.E.R.C. ¶ 61,131 (Nov. 1, 2017).

is $162,112,131, which includes $56,968,506 for NERC funding; $104,544,752 for Regional Entity funding; and $598,873 for WIRAB funding."[26] NERC stated "it will continue to allocate costs to end users in the United States based on net energy for load."[27] The total United States net funding requirement for the ERO enterprise is "$0.0000407 per kWh, based on the aggregate net energy for load of the United States in 2016."[28] The FERC also granted NERC's request to allocate $500,000 in penalty monies to its assessment stabilization reserve and approved NERC's withdrawal of $600,000 "from the assessment stabilization reserve," resulting in "a net withdrawal of $100,000."[29] The FERC did not require NERC to submit quarterly reports on the progress of geomagnetic disturbance research, as suggested by one commenter, but did note that NERC had other upcoming reporting requirements associated with that program.[30]

III. RELIABILITY STANDARDS

A. Petition of NERC for Approval of Errata to Voltage and Reactive Control Reliability Standards

On August 18, 2017, the NERC filed a petition seeking FERC approval of errata to mandatory and enforceable Reliability Standards VAR-001-4.1 (Voltage and Reactive Control), VAR-002-4 (Generator Operation for Maintaining Network Schedules), and VAR-501-WECC-3 (Power System Stabilizer).[31]

The NERC periodic review team reviewed Reliability Standards VAR-001-4.1, VAR-002-4, and VAR-501-WECC-3 and determined that these "Reliability Standards are sufficient to protect reliability, each meets its reliability objective and that no immediate substantive revisions are necessary."[32] Nevertheless, the periodic review team did identify and recommend changes in order to correct errata in each of the three Reliability Standards.[33] For proposed Reliability Standard VAR-001-4.2, the proposed changes included the use of the term "Operations Planning" instead of "Operational Planning" throughout; modifications to several Measures; and grammatical corrections in Requirement R4.[34] Proposed Reliability Standard VAR-002-4.1 corrects "capitalization of the defined term "Reactive Power" in Requirement R4, footnote 4."[35] Lastly, in proposed Reliability Standard VAR-501-WECC-3.1, "Transmission Operator" replaces the term "Transmission Planner" in the violation severity level assignments.[36] On September 26, 2017,

26. *Id.* at P 6.

27. *Id.*

28. *Id.*

29. *Id.* at PP 13-14.

30. 161 F.E.R.C. ¶ 61,131 at PP 9, 15.

31. Petition of the NERC for Approval of Errata to Voltage and Reactive Control Reliability Standards, *North Am. Elec. Reliability Corp*., FERC Docket No. RD17-7-000 (Aug. 18, 2017) [hereinafter NERC Petition for Approval of Errata].

32. *Id.* at 2.

33. *Id.* at 2-3.

34. *Id.* at 4.

35. *Id.*

36. NERC Petition for Approval of Errata, *supra* note 31, at 4-5.

the FERC issued a letter order approving the proposed regional Reliability Standard VAR-001-4.1, VAR-002-4 and VAR-501-WECC-3.[37]

B. Joint Petition of NERC and ReliabilityFirst for Approval of Proposed Regional Reliability Standard BAL-502-RF-03

On September 7, 2017, the NERC and ReliabilityFirst Corporation (ReliabilityFirst) filed a joint petition seeking approval of proposed regional Reliability Standard BAL-502-RF-03 (Planning Resource Adequacy Analysis, Assessment and Documentation).[38] NERC and ReliabilityFirst also requested approval of the associated "implementation plan for the proposed regional Reliability Standard," "violation risk factors and violation severity levels," and "retirement of regional Reliability Standard BAL-502-RFC-02."[39] The proposed regional Reliability Standard BAL-502-RF-03 establishes "common criteria, based on "one day in ten year" loss of load expectation principles, for the analysis, assessment, and documentation of resource adequacy for load in the ReliabilityFirst region."[40]

The "proposed regional Reliability Standard BAL-502-RF-03" addresses the FERC directives to: "(1) add time horizons applicable to the requirements; and (2) consider including a requirement that the planning coordinators identify any gap between the needed amount of planning reserves and the documented projected planning reserves determined from the resource adequacy analysis."[41] On October 16, 2017, the FERC issued a letter order approving the proposed regional Reliability Standard BAL-502-RF-03.[42]

C. Joint Petition of NERC and SERC for Approval of Proposed Regional Reliability Standard PRC-006-SERC-02

On September 8, 2017, the NERC and SERC filed a joint petition seeking approval of proposed regional Reliability Standard PRC-006-SERC-02 (Automatic Under-frequency Load Shedding (UFLS) Requirements).[43] NERC and SERC also requested approval of the associated "effective date for the proposed regional Reliability Standard, violation risk factors and violation severity levels, and retirement of regional Reliability Standard PRC-006-SERC-01."[44] The proposed regional Reliability Standard PRC006-SERC-02 establishes "requirements

37. Letter Order, Joint Petition for Approval of Errata to Voltage and Reactive Control Reliability Standards, FERC Docket No. RD17-7-000 (Sept. 26, 2017).

38. Petition for Approval of Proposed Regional Reliability Standard BAL-502-RF-03, *North Am. Elec. Reliability Corp*., FERC Docket No. RD17-8-000 (Sept. 7, 2017).

39. *Id.* at 1-2.

40. *Id.* at Exhibit C.

41. *Id.* at 2.

42. Letter Order, Joint Petition for Approval of Proposed Regional Reliability Standard BAL-502-RF-03, *North Am. Elec. Reliability Corp*., FERC Docket No. RD17-8-000 (Oct. 16, 2017) [hereinafter Oct. 16, 2017 Letter Order].

43. Joint Petition of NERC and SERC for Approval of Proposed Regional Reliability Standard PRC-006-SERC-02, *North Am. Elec. Reliability Corp*., FERC Docket No. RD17-9-000 (Sept. 8, 2017) [hereinafter NERC and SERC Joint Petition].

44. *Id.* at 1-2.

for the design, implementation, and analysis of automatic UFLS programs among all SERC applicable entities."[45]

The "proposed regional Reliability Standard PRC-006-SERC-02 incorporates revisions" that allow "Planning Coordinators to select the peak season for UFLS plans" and clarify "the load that can be used for UFLS schemes in the SERC region."[46] The proposed revisions seemingly resulted from the periodic review of regional Reliability Standard PRC-006-SERC-01.[47] In approving regional Reliability Standard PRC-006-SERC-01, the FERC stated that "the regional Reliability Standard is 'designed to work in conjunction with NERC Reliability Standard PRC-006-1 to mitigate the consequences of an under-frequency event effectively while accommodating differences in system transmission and distribution topology among SERC planning coordinators due to historical design criteria, makeup of load demands, and generation resources.'"[48] Proposed regional Reliability Standard PRC-006-SERC-02 continues to satisfy these criteria.[49] On October 16, 2017, the FERC issued a letter order approving the proposed regional Reliability Standard PRC-006-SERC-02.[50]

D. Petition of NERC for Approval of Proposed Reliability Standards CIP-013-1, CIP-005-6 and CIP-010-3

On September 26, 2017, the NERC filed a petition seeking approval of proposed Reliability Standards CIP-013-1 (Cyber Security – Supply Chain Risk Management), CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), and CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments) and their associated violation risk factors and violation severity levels, implementation plans, and effective dates.[51] NERC submitted the proposed supply chain risk management Reliability Standards in response to the Federal Energy Regulatory Commission's (FERC) directive in Order No. 829.[52]

NERC states that the proposed Reliability Standards apply only to medium and high impact Bulk Electric System (BES) Cyber Systems.[53] The proposed Reliability Standards focus on software integrity and authenticity, vendor remote access protections, information system planning and vendor risk management and procurement controls.[54] In its petition, NERC asserted the proposed Reliability Standards "are designed to reduce the likelihood that an attacker could exploit legitimate vendor patch management processes to deliver compromised software

45. *Id.* at 1.

46. *Id.* at 2.

47. *Id.*

48. NERC and SERC Joint Petition, *supra* note 43, at 7.

49. *Id.*

50. *See generally* Oct. 16, 2017 Letter Order, *supra* note 42.

51. Petition of the NERC for Approval of Proposed Reliability Standards CIP-013-1, CIP005-6 and CIP-010-3 addressing Supply Chain Cybersecurity Risk Management, *North Am. Elec. Reliability Corp*., FERC Docket No. RD17-13-000 (Sept. 26, 2017) [hereinafter Sept. 26, 2017 Petition for Approval].

52. *Id.* at 1; *see also* Order No. 829, *Revised Critical Infrastructure Protection Reliability Standards*, 156 F.E.R.C. ¶ 61,050 at P 43 (2016).

53. Sept. 26, 2017 Petition for Approval, *supra* note 51, at 4.

54. *Id.* at 8.

updates or patches."[55] The proposed Reliability Standards also addressed "vendor remote access-related threats, including the threat that vendor credentials could be stolen and used to access a BES Cyber System without the Responsible Entity's knowledge," "the risk that Responsible Entities could unintentionally plan to procure and install unsecure equipment or software within their information systems," "the risk that Responsible Entities could enter into contracts with vendors who pose significant risks to their information systems," and "the risk that a compromised vendor would not provide adequate notice of security events and vulnerabilities, and related incident response to Responsible Entities with whom that vendor is connected."[56]

The newly proposed "Reliability Standard CIP-013-1 requires Responsible Entities to develop and implement plans to address supply chain cybersecurity risks during the planning and procurement of high and medium impact BES Cyber Systems."[57] NERC states the Reliability Standards "improves reliability by requiring Responsible Entities to implement processes" that "identify and assess cybersecurity risks to the BES from vendor products and services in their planning activities for high and medium impact BES Cyber Systems; and [to] include specified security concepts in their procurement activities for high and medium impact BES Cyber Systems."[58]

The newly proposed Reliability Standard CIP-005-6 included two new parts, Parts 2.4 and 2.5, which addressed vendor remote access and proposed Reliability Standard CIP-010-3 includes a new part, Part 1.6, to address software integrity and authenticity.[59]

On January 18, 2018, the FERC issued a notice of proposed rulemaking (NOPR) proposing to approve Reliability Standards CIP-013-1, CIP-005-6, and CIP-010-3 and proposing that NERC develop and submit certain modifications to the supply chain risk management Reliability Standards.[60]

E. Petition of NERC for Approval of Proposed Reliability Standard TPL-007-2

On January 22, 2018, the NERC filed a petition seeking approval of proposed regional Reliability Standard TPL-007-2.[61] The proposed Reliability Standard focuses on mitigating the risk of instability, uncontrolled separation, and Cascading due to geomagnetic disturbances (GMDs) through application of Operating Procedures and strategies that address potential impacts identified in a registered entity's assessment.[62] The proposed standard addresses the FERC's directives in

55. *Id.* at 3.

56. *Id.* at 3-4.

57. *Id.* at 4.

58. Sept. 26, 2017 Petition for Approval, *supra* note 51, at 4.

59. *Id.* at 31-33.

60. Notice of Proposed Rulemaking, *Supply Chain Risk Management Reliability Standards*, F.E.R.C. STATS. & REGS. ¶ 61,044, 83 Fed. Reg. 3,433 (2018).

61. Petition for Approval of Proposed Reliability Standard TPL-007-2, *North. Am. Elec. Reliability Corp*., FERC Docket No. RD18-8-000 (Jan. 22, 2018).

62. *Id.* at exh. E.

Order 830 by requiring entities to perform supplemental GMD Vulnerability Assessments based on the supplemental GMD event: a second defined event that accounts for localized peak effects of GMDs that is based on individual station measurements.[63] It also requires entities to perform supplemental thermal impact assessments of applicable power transformers based on geomagnetically induced current (GIC) information for the supplemental GMD event, and to implement processes that obtain GIC monitor and magnetometer data.[64] The proposed standard also implements the deadlines specified by the FERC for the development and completion of any necessary Corrective Action Plans to address system performance issues resulting from the benchmark GMD event.[65] On May 17, 2018, the FERC issued a notice of proposed rulemaking (NOPR) proposing to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date for proposed Reliability Standard TPL-007-2.[66] In addition, the NOPR proposes to direct NERC "to develop and submit modifications to the Reliability Standard to require applicable entities to develop and implement corrective action plans to mitigate supplemental GMD event vulnerabilities."[67]

IV. RELIABILITY COMPLIANCE, ENFORCEMENT, AND NOTICE OF PENALTY

A. Order Accepting the Compliance Monitoring and Enforcement Program

On February 21, 2017, the NERC filed its annual informational filing reviewing the progress of the risk-based compliance and enforcement program, in accordance with the FERC's February 19, 2015 Order on Electric Reliability Organization Reliability Assurance Initiative (RAI) Requiring Compliance Filing, and the November 4, 2015 Order Conditionally Accepting Compliance Filings.[68] In its filing, NERC also proposed the following enhancements to the risk-based Compliance Monitoring and Enforcement Program (CMEP) based on the Electric Reliability Organization Enterprise's experience with the implementation of these programs over 2016: (1) providing minimal risk Compliance Exceptions identified through self-logging to FERC non-publicly; and (2) expanding the use of Compliance Exceptions to include certain moderate risk noncompliance currently processed under the Find, Fix, Track, and Report program.[69]

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63. *Id.*

64. *Id.*

65. *Id.*

66. Notice of Proposed Rulemaking, *Geomagnetic Disturbance Reliability Standard*, F.E.R.C. STATS. & REGS. ¶ 61,126, 83 Fed. Reg. 23,854 (2018).

67. *Id.* at P 41.

68. *North Am. Elec. Reliability Corp*., 150 F.E.R.C. ¶ 61,108 (2015) [hereinafter February 19 Order]. In the February 19 Order, the FERC conditionally approved the implementation of the risk-based CMEP, finding that the "overall goal of focusing ERO and industry compliance resources on higher-risk issues that matter more to reliability is reasonable." *Id*. at P 2. The FERC also directed NERC, among other things, to submit an annual informational filing, within one year from the date of the issuance of the order; to review the progress of the risk-based CMEP; and to address a number of other specific topics regarding oversight processes and implementation assessment. *Id*. at PP 32, 42-43, 46, 49-52; *North Am. Elec. Reliability Corp*., 153 F.E.R.C. ¶ 61,130 (2015) [hereinafter November 4 Order]. The November 4 Order conditionally accepted NERC's May 20 and July 6 compliance filings.

69. November 4 Order, *supra* note 68, at P 2.

On November 16, 2017, the FERC issued an order accepting the 2016 CMEP Annual Report, and terminating the annual informational filing requirement regarding the RAI as long as NERC: (1) "continue[d] to include compliance exceptions in the annual 'sampling' filing it makes pursuant to the FFT Order; and (2) continue[d] to include information on the RAI program, including observed trends and examples of matters treated as compliance exceptions, in the CMEP Report prepared for NERC's Board of Trustees Compliance Committee."[70] The FERC also denied NERC's request for approval of the "two proposed changes to the CMEP."[71]

The FERC denied NERC's request for removing the public posting for Compliance Exceptions discovered through self-logging because "information on NERC's resolution of compliance and enforcement matters should be transparent and publicly available and processing of noncompliance should reflect the relative risk level of the violation."[72] In addition, the FERC "found that the additional burden of public posting is minimal, and that preserving transparency in compliance and enforcement matters provides meaningful benefits, by educating industry and ensuring consistency across NERC's and the Regional Entities' compliance and enforcement programs."[73]

Although the FERC denied the requested enhancements, it encouraged NERC to continue proposing program enhancements in the future.[74] The FERC also expressed its continued support of the "general direction of NERC's compliance program towards a focus on risk-based compliance."[75]

V. RELIABILITY REPORTS AND ASSESSMENTS

A. NERC's 2017 Long-Term Reliability Assessment

On December 13, 2017, NERC issued the 2017 Long-Term Reliability Assessment (LTRA).[76] The LTRA is an annual report compiled by NERC's Reliability Assessment and Performance Analysis Group to "fulfil[l] the ERO's Rules of Procedure, which instructs NERC to conduct periodic assessments of the North American bulk power system (BPS)."[77] The 2017 LTRA employs a new format "to highlight data and information that is especially impactful to the long-term outlook of the North American BPS."[78] The LTRA "identifies potential risks to inform industry planners and operators, regulators, and policy makers" and includes four key findings.[79]

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70. *North Am. Elec. Reliability Corp.*, 161 F.E.R.C. ¶ 61,187 at P 23 (2017).

71. *Id.* at P 1.

72. *Id.* at P 24.

73. *Id.* at P 28.

74. *Id.* at P 23.

75. 161 F.E.R.C. ¶ 61,187 at P 37.

76. NORTH AMERICAN ELECTRIC RELIABILITY CORP., 2017 LONG-TERM RELIABILITY ASSESSMENT, (2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf (last visited Jul. 28, 2018) [hereinafter LTRA].

77. *Id.* at 4.

78. *Id.*

79. *Id.* at 5.

First, NERC found that "[r]ecent retirement announcements in Texas RE-ERCOT and the canceled nuclear plant expansion in SERC-E result in projected margin shortfalls for both assessment areas."[80] Specifically, "SERC-E's Anticipated and Prospective Reserve Margins fall below the Reference Margin Level . . . beginning in Summer 2020" and "declin[e] for the remainder of the assessment period."[81] The LTRA also found that "ERCOT's Prospective Reserve Margins remain adequate."[82] While all "[o]ther Regions project sufficient margins during the next five years."[83]

Second, NERC noted that "conventional generation continues to retire with rapid additions of natural gas, wind, and solar resources."[84] According to the LTRA, "NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in three areas: NPCC-New England, -Ontario, and –Maritimes."[85] The drivers for this are "[c]ontinued advancements of energy efficiency programs and behind-the meter resources, combined with a general shift in North America to economic growth that is less energy-intensive," and the adoption of energy efficiency policies in 30 states.[86] However, NERC noted that "[a] rapid onset of emerging technologies, including the rapid penetration of electric vehicles, could create unexpected impacts on load growth that might not be captured in load forecasts."[87]

Third, NERC found that "[t]he changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services and fuel assurance."[88] According to the LTRA, "[c]onventional generation from coal, oil, and nuclear units continues to retire as natural gas, wind, and solar lead planned additions."[89] These changes to the "resource mix, combined with the onset of new technologies (e.g., inverter-based resources), are altering the operational characteristics of the grid and require changes to planning and operating approaches."[90] As a result, there are "new considerations for reliability and resilience planning, such as ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system."[91]

Finally, NERC found that "[d]espite low or flat load growth, a total of 6,200 circuit miles of new transmission is planned throughout the assessment period with more than 1,100 circuit miles currently under construction."[92] Because "[t]he North American BPS was designed largely around central-station generation as

80. *Id.*
81. LTRA, *supra* note 76, at 8.
82. *Id.*
83. *Id.*
84. *Id.* at 5.
85. *Id.* at 12.
86. LTRA, *supra* note 76, at 12.
87. *Id.*
88. *Id.* at 5.
89. *Id.* at 13.
90. *Id.*
91. LTRA, *supra* note 76, at 13.
92. *Id.* at 5.

the primary source of electricity; new transmission will be needed to integrate renewable resources."[93]

NERC issued nine recommendations to address these four key findings. These recommendations are direct to (1) policy makers and regulators; (2) industry; and (3) NERC. They are as follows:

> Policy Makers and Regulators
> - Support essential reliability services.
> - Recognize time needed to maintain reliability.
> - Consider industry study recommendations when reviewing infrastructure requirements.
> - Focus on reliability and resilience attributes to limit exposure to risk.
>
> Industry
> - Support technologies that contribute to essential reliability services.
> - Integrate DERs with increased visibility.
> - Report on expected reliability concerns.
>
> NERC
> - Conduct comprehensive evaluation of Reliability Standards.
> - Monitor reserve margin short falls. [94]

B. Paul Parfomak: Congressional Research Service: NERC Standards for Bulk Power Physical Security: Is the Grid More Secure?

On March 19, 2018, the Congressional Research Service issued a report by Paul Parfomak addressing the physical security of the bulk energy system (BES).[95] Specifically, after summarizing the basics, including "changes to the physical security of the electric power grid since the promulgation of NERC's physical security standards," and "the current risk environment for the bulk power system"; "key requirements of NERC's security standards."[96] Parfomak also addresses "observable changes in the utility sector related to physical security" and provides "an overview of proposed legislation and a discussion of policy issues for Congress."[97]

Parfomak identifies several reasons why, despite the fact that the "FERC's statutory authority for grid reliability and NERC's reliability standards both include provisions for oversight and enforcement, congressional oversight of physical security implementation may be a challenge."[98] To address this, Parfomak suggests that "if Congress decides the information as currently structured is insuf-

93. *Id.* at 32.

94. *Id.* at 6.

95. Paul W. Parfomak, *NERC Standards for Bulk Power Physical Security: Is the Grid More Secure?* CONGRESSIONAL RESEARCH SERVICE (2018), https://fas.org/sgp/crs/homesec/R45135.pdf (last visited July 28, 2018) [hereinafter Parfomak].

96. *Id*. at 1.

97. *Id.*

98. *Id.* at 17.

ficient to draw reliable conclusions about the status of bulk power physical security as a whole, it may revisit how the responsible agencies collect, measure, and report it."[99]

Parfomak also suggests that, to address issues with "competition for limited capital investment resources" and the need to "justif[y] security spending to corporate boards and utility rate regulators," "Congress may examine whether the overall level of investment appropriately reflects the level of security risk facing the bulk power system, and whether any cost-recovery barriers are preventing assets owners from making investments necessary to secure the grid."[100]

Parfomak advises that Congress also consider whether industry is striking the appropriate balance between hardening the grid and investing in resiliency measures.[101] Hardening the grid consists of working to "prevent attacks by monitoring critical facilities to identify would-be attackers before they attempt an attack, preventing attacker access to critical assets, and otherwise hardening facilities to make them more physically secure to protect against attack and equipment failure."[102] Improving the resiliency of the grid means "mak[ing] the broader power system more 'resilient' to a successful attack on particular assets through an enhanced ability to manage loads, reroute power flows, and access other sources of generation to reduce the potential of blackouts even if critical assets are disabled."[103]

Finally Parfomak suggests that Congress "examine how federal and electric sector threat information is developed and used by critical asset owners, and how limitations and uncertainty of this information may affect physical security of the electric grid"[104] He issues this recommendation because "[t]he utility industry's physical security risk assessments rely upon threat information from the federal government, among other sources," and because of "[c]oncerns about the quality and specificity of federal threat information have long been an issue across all critical infrastructure sectors."[105]

C. Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System

In November 2017, NERC issued a Special Reliability Assessment (SRA) addressing the potential impacts to the Bulk Power System (BPS) as a result of a large disruption on the natural gas system.[106] The SRA "identifies major clusters of natural gas generation and conducts a screening analysis to determine at a high

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99. *Id.* at 18.

100. Parfomak, *supra* note 95, at 18.

101. *Id*. at 19.

102. *Id.* at 18-19.

103. *Id.* at 19.

104. *Id.* at 20.

105. Parfomak, *supra* note 95, at 19-20.

106. NERC, SPECIAL RELIABILITY ASSESSMENT: POTENTIAL BULK POWER SYSTEM IMPACTS DUE TO SEVERE DISRUPTIONS ON THE NATURAL GAS SYSTEM (2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf (last visited Jul. 28, 2018) [hereinafter SRA].

level whether there are further issues that need investigation."[107] NERC makes nine key findings and issues nine recommendations to regulators and policy makers, industry, and NERC.[108]

First, NERC finds that "[n]atural gas facility disruptions can have varying impacts depending on geographical location and overall infrastructure dynamics."[109] Second, "NERC's power flow simulation demonstrates that 18 out of 24 groups of gas-dependent generators studied experience transmission challenges during an extreme event."[110] Third, NERC finds that, "[t]he demand for natural gas storage has increased significantly and has altered the traditional operations of these facilities in order to meet electric demand along with the traditional demands of the natural gas industry."[111] Fourth, NERC notes that because, "Aliso Canyon has different characteristics than most traditional natural gas storage facilities, "[and] that "Aliso Canyon outage poses additional reliability concerns in Southern California."[112] Fifth, NERC explains that, "[f]irm natural gas pipeline transportation, in addition to dual fuel capability and ample infrastructure, provide the highest level of reliability for natural gas delivery."[113] Sixth, NERC notes that, "[m]any mitigation strategies have been and can be employed to reduce potential impacts of a natural gas disruption."[114] Seventh, NERC finds that, "[n]atural gas supply sources have become more diversified, reducing the likelihood of natural gas infrastructure outages affecting electric generation."[115] Eighth, NERC states that, "[r]ecent FERC Orders continue to promote natural gas/electric coordination. FERC Orders 787 and 809 have supported natural gas/electric system coordination by increasing the synchronization of operations between the two industries."[116] Finally, NERC finds that, "[c]omprehensive planning by Planning Coordinators can significantly increase system resilience."[117]

The NERC makes the following recommendations to address the identified key issues: [118]

Regulators and Policy Makers

- During the planning process, system planners should work with regulators to incorporate expeditious consideration of air permit waivers, which may be needed for resilience purposes; dual fuel,

107. *Id.* at viii.
108. *Id.* at viii-x.
109. *Id.* at viii.
110. *Id.* at viii.
111. SRA, *supra* note 106, at ix.
112. *Id.*
113. *Id.*
114. *Id.*
115. *Id.*
116. SRA, *supra* note 106, at ix.
117. *Id.*
118. *Id.*

back-up pipeline capacity, and/or alternative sources of supply should be required in areas with significant risk.[119]

- Regulators should consider fuel diversity as they evaluate electric system plans and establish energy policy objectives. Additionally, regulators and policy makers should expedite licensing of new transmission and natural gas facilities to diversify and distribute risk.[120]
- Cyber and physical security needs to be diligently considered by regulators . . . Additionally, gas industry regulators should be engaged to establish cyber security standards that match those of the NERC reliability standards.[121]
- The Department of Energy (DOE) should have the Energy Information Administration (EIA) collect data that quantify and assess the use of dual fuel storage for natural-gas-fired generation and whether that storage has inventory.[122]

Industry

- NERC registered entities should consider the loss of key natural gas infrastructure in their planning studies.[123]
- Owners and operators of dual fuel capable generators must ensure operability of secondary fuel.[124]
- Natural gas and electric industries must continue to advance coordination as the electric industry continues to become a larger percentage of total natural gas throughput.[125]

NERC

- NERC should enhance its reliability guidelines and/or standards.[126]
- NERC should enhance its Generator Availability Data System (GADS) database.[127]

D. Staff Report to the Secretary on Electricity Markets and Reliability

In August 2017, the U.S. Department of Energy (DOE) issued a report in response to an April 14, 2017, request from Energy Secretary Rick Perry for "a study to examine electricity markets and reliability."[128] The study addresses the

119. *Id.*
120. *Id.*
121. SRA, *supra* note 106, at ix.
122. *Id.*
123. *Id.*
124. *Id.* at x.
125. *Id.*
126. SRA, *supra* note 106, at x.
127. *Id.*
128. UNITED STATES DEP'T OF ENERGY, STAFF REPORT TO THE SECRETARY ON ELECTRICITY MARKETS AND RELIABILITY 1 (2017), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf (last visited Jul. 28, 2018) [hereinafter DOE STAFF REPORT].

three issues identified by Secretary Perry with a focus "on the present trajectory of trends that are of particular concern."[129]

The first issue is, "[t]he evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets."[130]

Next, the study examines, "[w]hether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future."[131]

Finally, it addresses, "[t]he extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants."[132]

The DOE Staff Report, "identified several critical issues central to protecting the long-term reliability of the electric grid."[133] These issues are divided into the three areas specified by Secretary Perry.

With respect to the first issue, DOE Staff make three findings.[134] First, that, "[w]hile centrally-organized markets have achieved reliable wholesale electricity delivery with economic efficiencies in their short-term operations, changing circumstances have challenged both centrally-organized and, to a lesser extent, vertically-integrated markets."[135] Further, DOE Staff anticipates that current, "[m]arket designs may be inadequate given potential future challenges," including variable renewable energy (VRE) resources, which will "put additional economic pressure on revenues for traditional baseload (as well as non-baseload) resources, requiring careful consideration of continued market evolutions."[136]

Second, DOE Staff find that, "[e]volving market conditions and the need to accommodate VRE have led to the increased flexible operation of generation and other grid resources."[137] The DOE Staff noted that, "[s]ome generation technologies originally designed to operate as baseload were not intended to operate flexibly, and in nuclear power's case, do not have a regulatory regime that allows them to do so."[138]

Third, DOE Staff noted that, "[s]ociety places value on attributes of electricity provision beyond those compensated by the current design of the wholesale market."[139] As a result, there are now, "a variety of state and private efforts that

129. *Id.*
130. *Id.*
131. *Id.*
132. *Id.*
133. DOE STAFF REPORT, *supra* note 128, at 10.
134. *Id.* at 10-11, 13.
135. *Id.* at 10.
136. *Id.*
137. *Id.*
138. DOE STAFF REPORT, *supra* note 128, at 10.
139. *Id.* at 11.

include keeping open or shutting down established baseload generators and incentivizing VRE generation" to address the fact that the wholesale electricity markets do not recognize or compensate many of the benefits associated with society's values.[140]

With respect to the second issue, DOE Staff make a single finding: "Markets recognize and compensate reliability, and must evolve to continue to compensate reliability, but more work is needed to address resilience."[141] This includes addressing fuel assurance, severe weather events, and changing market conditions.[142]

Finally, DOE Staff identified four issues associated with the third area of interest.[143] First, "[t]he biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation."[144] This is in part because "[t]he increased use of natural gas in the electric sector has resulted in sustained low wholesale market prices that reduce the profitability of other generation resources important to the grid."[145]

Second, DOE Staff identifies "[a]nother factor contributing to the retirement of power plants [as] low growth in electricity demand."[146] Low growth can be attributed in part to energy efficiency policies.[147] According to the DOE Staff Report, "[t]he combination of slow growth in electricity demand and the 390,500 MW of capacity additions from 2002 to 2016 made significant amounts of older, higher-cost capacity redundant."[148]

Third, the "[d]ispatch of VRE has negatively impacted the economics of baseload plants."[149] The growth in VRE resources is due to "State renewable portfolio standards (RPS) . . . followed by Federal tax credits and government research (which contributed to the dramatic drop in wind and solar technology costs)."[150]

Fourth, and finally, DOE Staff find that "[i]nvestments required for regulatory compliance have also negatively impacted baseload plant economics, and the peak in baseload plant retirements (2015) correlated with deadlines for power plant regulations as well as strong signals of future regulation."[151] The regulations necessitating these investments include the Mercury and Air Toxics Standard (MATS), the Clean Power Plan, and the Cooling Water Intake Rule.[152]

According to the report, "the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience."[153] DOE Staff provide eight recommendations, some of which "fit squarely

140. *Id.*
141. *Id.*
142. *Id.* at 11-12.
143. DOE STAFF REPORT, *supra* note 128, at 13-14.
144. *Id.* at 13.
145. *Id.*
146. *Id.* at 13.
147. *Id.*
148. DOE STAFF REPORT, *supra* note 128, at 13.
149. *Id.* at 13-14.
150. *Id.* at 13.
151. *Id.* at 14.
152. *Id.* at 14.
153. DOE STAFF REPORT, *supra* note 128, at 14.

within DOE's authority, while others might fall to other government agencies or private organizations."[154] The topics of these recommendations are identified as: (1) wholesale markets; (2) valuation of essential reliability services; (3) Bulk Power System (BPS) resilience; (4) research and development of next-generation/21st century grid reliability and resilience tools; (5) support of Federal and regional approaches to electricity workforce development and transition assistance; (6) energy dominance; (7) infrastructure development; and (8) electric-gas coordination.[155] DOE Staff also identifies several areas for further research, which fall into four categories: (1) market structure and pricing; (2) reliability and resilience; (3) cost and affordability; and (4) regulatory.[156]

E. Summer 2018 Energy Market and Reliability Assessment

On May 17, 2018, the FERC released its Summer 2018 Energy Market and Reliability Assessment (Summer Assessment).[157] The Summer Assessment contains a "summary of the reliability challenges" the FERC expects markets will encounter in the summer months and a discussion of current and future trends and how industry developments could impact energy markets.[158]

The FERC assessed information from the National Oceanic and Atmospheric Administration (NOAA), which forecasted an "above-normal chance for higher than average temperatures," for certain regions for the months of June, July, and August.[159] Despite above-average temperatures, the NERC forecasted that reserve margins are expected to be adequate in most regions, with the exception of the Electric Reliability Council of Texas (ERCOT).[160] ERCOT anticipates its reserve margin will be below its reference margin due to significant resources changes attributable to capacity retirement and delays in construction of new resources.[161] Despite the challenges that ERCOT anticipates, it expects to have "sufficient operational tools to manage tight reserves and maintain system reliability."[162]

The FERC anticipates that Summer 2018 could see "near-record-high gas demand from natural gas-fired power generators."[163] The FERC attributes significant gas generation to the addition of "over 16,000 MW of new capacity to the natural-gas fired generator fleet" and "relatively low natural gas prices."[164] The EIA forecasted natural gas averaging 37 percent of total generation for June, July, and August 2017.[165] Natural gas futures prices for Summer 2018 are anticipated

154. *Id.* at 126.

155. *Id.* at 126-128.

156. *Id.* at 128-129.

157. FERC, SUMMER 2018 ENERGY MARKET AND RELIABILITY ASSESSMENT (May 17, 2018), *available at* https://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2018/05-17-18.pdf [hereinafter SUMMER ASSESSMENT].

158. *Id.* at slide 2.

159. *Id.* at slide 3

160. *Id.* at slide 2.

161. *Id.* at slide 5.

162. SUMMER ASSESSMENT, *supra* note 157, at slide 5.

163. *Id.* at slide 8.

164. *Id.*

165. *Id.*

to be lower than those for Summer 2017.[166] The largest decrease in summer futures occurred in West Texas, due to large increases in the natural gas production associated with increasing oil production from the Permian Basin.[167] The Summer Assessment predicts that natural gas storage levels will remain within the five-year average.[168] However, due to operational constraints in southern California, regional storage deficits are expected to continue in the western regions.[169]

The FERC conducted an analysis of specific grid locations within RTO/ISO market regions that experienced higher congestion prices during Summer 2017.[170] The higher congestion prices correlate to areas where it is "more difficult to deliver power or where additional generation is particularly valuable for relieving congestion."[171] The FERC stated that it "will continue to analyze congestion in RTO/ISO markets" during Summer 2018.[172] The FERC indicated it is hopeful that the increase in transmission upgrades that entered operation in the RTO/ISO markets since Summer 2017 "will help relieve grid congestion."[173]

The Summer Assessment explains the changes to the PJM and ISO New England capacity markets in an effort to "enhance reliability through market incentives."[174] The changes will alter the capacity markets incentivize or penalize capacity suppliers based on their performance "when called upon by system operators during shortage[s]."[175] The FERC also describes the trends in demand response resources in Eastern RTOs.[176] The Summer Assessment finds that "[w]hile the amounts of capacity provided by demand response providers have varied, the contribution to the systems has largely remained stable over the past several years."[177] There were no activations of capacity-based demand response in the Eastern RTOs, but the FERC anticipates that the capacity market changes described above and the full integration of demand-response resources into competitive energy and reserves markets will affect demand response in ISO New England.[178]

The Summer Assessment anticipates that the snowpack, on which hydroelectric generation in the California ISO relies, may melt faster than usual due to the warmer-than-normal forecasted temperatures. [179] If it does, there may be a lesser amount of hydroelectric generation available during the summer to "meet peak

166. *Id.* at slide 9.
167. SUMMER ASSESSMENT, *supra* note 157, at slide 9.
168. *Id.* at slide 10.
169. *Id.*
170. *Id.* at slide 11.
171. *Id.*
172. SUMMER ASSESSMENT, *supra* note 157, at slide 11.
173. *Id.* at slide 11.
174. *Id.* at slide 12.
175. *Id.*
176. *Id.* at slide 13.
177. SUMMER ASSESSMENT, *supra* note 157, at slide 13.
178. *Id.*
179. *Id.* at slide 14.

electric demand."[180] The CAISO typically "offset[s] lower hydro generation levels" with increased "natural gas-fired capacity."[181] This year, however, the FERC anticipates that "natural gas supply limitations in southern California" may impact the CAISO's "natural gas generation fleet."[182]

The FERC expects increased use of battery storage across the United States.[183] The Summer Assessment identifies significant "installations in PJM and California," with the CAISO adding more battery storage capacity "than any other ISO" between 2016 and 2017.[184] The battery storage capacity in operation increased 30 % from 2017, and an additional 63 MW of battery storage capacity is anticipated in Summer 2018.[185]

The Summer Assessment concludes that "capacity and fuel availability" will be adequate in most regions to support higher-than-normal summer conditions, with the exception of ERCOT, which has procedures in place to maintain reliability.[186] Additionally, there appears to be adequate natural gas supply to support increased demand of generators.[187] The FERC stated it will continue to monitor the generating capacity in ERCOT and the hydro and natural gas availability in California through Summer 2018.[188]

VI. GRID SECURITY AND CRITICAL ASSET SECURITY

A. Order No. 833-A, Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information

On May 17, 2018, the FERC issued Order No. 833-A, "Order on Clarification and Rehearing."[189] The FERC issued Order No. 833 on November 17, 2016, amending the FERC's regulations at 18 C.F.R. §§ 375.309, 375.313, 388.112, and 388.113 to implement the Fixing America's Surface Transportation (FAST) Act of 2015.[190] The FAST Act required the FERC to issue regulations providing:

> (1) the criteria and procedures for designating information as Critical Electric Infrastructure Information; (2) a specific prohibition on unauthorized disclosure of Critical

180. *Id.*

181. *Id.* at slide 14.

182. SUMMER ASSESSMENT, *supra* note 157, at slide 14.

183. *Id.* at slide 15.

184. *Id.*

185. *Id.*

186. *Id.* at slide 16.

187. SUMMER ASSESSMENT, *supra* note 157, at slide 16.

188. *Id.*

189. Order No. 833-A, *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, 163 F.E.R.C. ¶ 61,125 (2018) [hereinafter Order No. 833-A].

190. *Id.* at 4 (citing Order No. 833, *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, F.E.R.C. Stats. & Regs. ¶ 61,123, 81 Fed. Reg. 93,732 (2016) (to be codified at C.F.R. pts. 375, 388) [hereinafter Order No. 833]); *see Fixing America's Surface Transportation Act*, PUB. L. NO. 114-94, section 61,003, 129 Stat. 1312, 1773-1779 (2015) (codified at 16 U.S.C. 824o-1)).

> Electric Infrastructure Information; (3) sanctions for the knowing and willful unauthorized disclosure of Critical Electric Infrastructure Information by Commission and Department of Energy (DOE) employees; and (4) a process for voluntary sharing of Critical Electric Infrastructure Information.[191]

The Edison Electric Institute (EEI) requested for clarification or rehearing on five parts of Order No. 833.[192]

First, EEI requested the FERC to reconsider the determination that Critical Electric Infrastructure Information (CEII) gathered by the FERC is to be shared with third parties.[193] EEI claimed that the FERC should not be permitted "to share information over a submitter's objection" which would amount to a violation of the Federal Power Act (FPA).[194] The FERC denied both clarification and rehearing on the issue, noting that the FPA permits voluntary sharing of CEII "with, between, and by" authorities, including federal authorities, and that the FAST Act does not prohibit sharing that information.[195] Further, the FERC stated that the revised rules permit the submitter to comment on potential disclosure and the final determination on whether to release CEII will be made by the CEII Coordinator.[196]

Second, EEI asserted that the FERC should "provide or clarify the criteria" used "to determine whether a member of the public is eligible to obtain CEII" from the FERC.[197] The FERC provided clarification by noting that Order No. 833 did clarify the criteria "a CEII requester must include in its statement of need."[198] Third, EEI stated the FERC should consider modernizing the non-disclosure agreements (NDA) entered into by CEII recipients.[199] The FERC clarified Order No. 833 by stating the minimum NDA elements were "not intended to be exhaustive or preclude additional provisions, as needed."[200] The FERC noted "the CEII Coordinator may consider" additional NDA provisions "on a case-by-case basis."[201]

Fourth, EEI requested the FERC clarify or outline stakeholder notification and an "opportunity to comment on potential disclosure or sharing of FERC-generated information" that may qualify as CEII.[202] The FERC clarified by explaining the FAST Act recognizes the FERC's expertise and experience in determining whether any information is "properly designated as CEII."[203] The FERC also stated that although a formal stakeholder process is warranted, the CEII Coordinator has the discretion to seek comments from stakeholders before releasing

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191. Order No. 833-A, *supra* note 189, at P 2.
192. *Id.* at P 1.
193. *Id.* at P 9.
194. *Id.*
195. *Id.* at P 10.
196. Order No. 833-A, *supra* note 189, at P 12.
197. *Id.* at P 16.
198. *Id.* at P 20 (clarifying that "a conclusory statement of need by a CEII requester will not suffice.").
199. *Id.* at P 23.
200. *Id.* at P 24 (citing Order No. 833, *supra* note 190, at P 92).
201. Order No. 833-A, *supra* note 189, at P 24.
202. *Id.* at P 26.
203. *Id.* at P 28.

commission-generated information.[204] Finally, EEI requested the FERC to clarify that any Department of Energy (DOE) CEII determination would be made pursuant to the FERC's regulations.[205] The FERC noted that it declined to "identify specific designation criteria and CEII procedures that would be required for DOE" and that the FAST Act neither compels DOE to change its regulations or comply with the FERC's regulations when designating information as CEII.[206]

B. Section 2(e): Assessment of Electricity Disruption Incident Response Capabilities

On May 11, 2017, President Donald Trump signed Executive Order No. 13800, "Presidential Executive Order on Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure" (Executive Order).[207] Section 2(e) of the Executive Order required the Secretary of Energy and the Secretary of Homeland Security to prepare an assessment of three areas: (1) "the potential scope and duration of a prolonged power outage associated with a significant cyber incident, as defined in Presidential Policy Directive 41 of July 26, 2016 (United States Cyber Incident Coordination), against the United States electric subsector;" (2) "the readiness of the United States to manage the consequences of such an incident;" and (3) "any gaps or shortcomings in assets or capabilities required to mitigate the consequences of such an incident."[208] The Executive Order gave the Secretaries 90 days to present the assessment to the President.[209]

On August 9, 2017, the Department of Homeland Security (DHS) released its assessment (Assessment).[210] The Assessment provides a background of the current U.S. electric grid, noting that "operating the grid is an enormously complex technical challenge" conducted by a variety of organizations across multiple jurisdictions.[211] The Assessment states that the grid has been resilient and reliable over the last 10 years, but increased use of industrial control systems (ICS) have exposed the grid to new cybersecurity vulnerabilities.[212] These vulnerabilities were on display in the 2015 Ukrainian cyberattacks, which resulted in outages for 225,000 customers for one to six hours.[213]

The first factor addressed by the Assessment is the scope and duration of a prolonged power outage from a significant cyber incident.[214] The Assessment

204. *Id.*

205. *Id.* at P 32.

206. Order No. 833-A, *supra* note 189, at P 33.

207. Exec. Order No. 13800 (May 11, 2017).

208. *Id.* § 2(e).

209. *Id.*

210. DEPARTMENT OF HOMELAND SEC., SECTION 2(E): ASSESSMENT OF ELECTRICITY DISRUPTION INCIDENT RESPONSE CAPABILITIES (Aug. 9, 2017), https://www.energy.gov/sites/prod/files/2018/05/f51/EO13800%20electricity%20subsector%20report.pdf [hereinafter DHS ASSESSMENT].

211. *Id.* at 1.

212. *Id.* at 2-3.

213. *Id.* at 6 (The case study notes that the BlackEnergy3 malware used to conduct the Ukrainian attacks has "been found within organizations that operate critical infrastructure in the United States and in partner nations.").

214. *Id.* at 7.

notes that the DOE conducted four cyberattack scenarios, with simulated load losses of 40 to 50,000 megawatts, to measure a range of risks.[215] Historically, grid restoration methods have been the result of physical damage to the system caused by severe weather and other natural hazards.[216] Current restoration processes are similar across utilities, but the rate at which power is restored can vary based on a variety of factors.[217] However, the Assessment notes that cyberattacks present different factors than natural disasters; cyberattacks can be triggered without warning, may selectively destroy specific types of equipment without regard to geography, may require different personnel to address, and could require communication and diagnostics that could strain current response systems.[218] All of these factors could likely increase the time needed to restore power across affected systems.[219]

The Assessment next considers the U.S. readiness to manage the consequences of a potential cyberattack and associated disruptions.[220] Securing the electric grid against cyberattacks are based in four "lines of effort": (1) planning, (2) information sharing, (3) incident response, and (4) exercises to secure the electric grid against cyber vulnerabilities and prolonged outages.[221] Planning includes both national and state or local plans, as well as industry or company-specific plans, which identify the responsibilities of different groups in the aftermath of an event.[222] Information sharing is complicated by jurisdictional and information security concerns.[223] Although there are national response mechanisms, electricity owners and operators are ultimately responsible for restoring power; utilizing existing frameworks and partnerships can facilitate faster recovery.[224] Finally, national and local response training exercises are an important part of developing knowledge about grid operations and improving communication in the event of a cyber incident.[225]

The Assessment also considered gaps in both response assets and capabilities.[226] The Assessment identified seven gap categories: (1) Cyber Situational Awareness and Incident Impact Analysis; (2) Roles and Responsibilities under Cyber Response Frameworks; (3) Cybersecurity Integration into State Energy Assurance Planning; (4) Electric Cybersecurity Workforce and Expertise; (5) Supply

215. DHS ASSESSMENT, *supra* note 210, at 7-8.

216. *Id.* at 8.

217. *Id.* at 9 (These factors can include "seasonally influenced demand, topography, population density, damage levels, inclement weather, and impacts to other critical infrastructure sectors that the electricity subsector relies on.").

218. *Id.* at 11.

219. *Id.* at 10.

220. DHS ASSESSMENT, *supra* note 210, at 16.

221. *Id.*

222. *Id.* at vii, 16 (At the national level, the three primary response plans include the National Preparedness System, the National Cybersecurity Incident Response Plan, and the National Infrastructure Protection Plan.).

223. *Id.* at 19.

224. *Id.* at 20-21.

225. DHS ASSESSMENT, *supra* note 210, at 23.

226. *Id.* at 26.

Chain and Trusted Partners; (6) Public-Private Cybersecurity Information Sharing; and (7) Resources for National Cybersecurity Preparedness.[227] Although both the public and private sectors are "increasing investments and improvements in cybersecurity planning, information sharing, training, and countermeasures," the system is still vulnerable to cyber threats like data breaches.[228] The Assessment includes suggestions for how to address each of the identified gaps, including significant cooperation between DOE, DHS, state governments, and industry partners to develop integrated and consistent response plans and strategies.[229]

VII. OTHER FERC RELIABILITY INITIATIVES

A. Grid Reliability and Resilience Pricing

On January 8, 2018, the FERC issued an "Order Terminating Rulemaking Proceedings, Initiating New Proceeding, and Establishing Additional Procedures" terminating Docket No. RM18-1-000, addressing Grid Reliability and Resilience Pricing, for failure to overcome the statutory threshold of finding that current regional transmission organization (RTO) and independent system operator (ISO) tariffs are unjust and unreasonable.[230]

However, the FERC notes that resilience remains an important issue warranting attention, thus the FERC opened a new proceeding in Docket No. AD18-7-000 with the express purpose of evaluating the resilience of the bulk power systems in regions operated by RTOs and ISOs.[231] To understand resilience, the FERC sought comments from both RTOs and ISOs regarding the "range of attributes, characteristics, and services" that would "allow the grid to withstand, adapt to, and recover from both naturally occurring and man-made disruptive events."[232] The Commission further directed RTOs/ISOs to provide the Commission with responses regarding threats to grid resilience and their mitigation strategies, for review.[233]

B. Order 842, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

On November 17, 2016, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to revise regulations requiring new interconnecting generating facilities, to install and enable primary frequency response capability.[234] In the NOPR, the FERC included minimum requirements for "droop and deadband parameters," and requirements to ensure response to frequency deviations in the pro forma Large Generator Interconnection Agreement (LGIA) and the pro forma

227. *Id.* at ix.

228. *Id.* at 26.

229. *Id.* at 26-31.

230. *Grid Reliability and Resilience Pricing*, 162 F.E.R.C. ¶ 61,012 (2018).

231. *Id.* at P 18.

232. *Id.* at PP 23-24.

233. *Id*. at P 26.

234. Order No. 842, *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, F.E.R.C. STATS. & REGS. ¶ 61,011, 82 Fed. Reg. 40,081 (2017) [hereinafter Order No. 842].

Small Generator Interconnection Agreement (SGIA) with exemptions for facilities regulated by the Nuclear Regulatory Commission.[235] The FERC noted that the requirements will serve to ensure "adequate primary frequency response capability" for evolving resource mixes that meet frequency response obligations under the NERC Reliability Standards.[236]

In public comments to the Order, commenters noted concern over the proposed standards.[237] Several commenters noted that the proposals contained in the NOPR did not provide specific provisions for electric storage resources.[238] Further, the Energy Storage Association (ESA) asserted that the proposed requirements in the NOPR may adversely impact electric storage resources.[239] ESA asks that a final rule "allow electric storage resources to specify a minimum set points" on frequency response and include an exemption to sustained response requirements facilities possessing the operational constraint of an inadequate state of charge to make sustained response infeasible.[240]

C. Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

On September 30, 2016, the FERC issued an order directing NERC to file a Geomagnetic Disturbance (GMD) research work plan (GMD Work Plan), evaluating the present reliance on single station readings for geomagnetic scaling.[241] NERC filed the plan on May 30, 2017.[242] The preliminary plan submitted to the FERC identified nine GMD related research areas, each with a specific expected deliverable.[243] The FERC accepted the preliminary plan and directed NERC to file a final updated GMD Work Plan with the FERC within in six months that is specific, with respect to the content and timing of the deliverables for each research task, while addressing "reliance on single station readings" adjusted for latitude.[244]

Implementing the submitted GMD plan requires significant financial investment, time, and outside expertise, leading the FERC to provide guidance in identifying which of the nine identified GMD related research areas should receive priority.[245] The FERC noted GMD research ought to prioritize improving Earth conductivity models (GIC Studies), followed by Harmonics analysis capability

235. *Id*. at PP 1-2.

236. *Id.* at 3.

237. *Id.* at PP 4, 8-9.

238. *Id*. at P 4.

239. Order No. 842, *supra* note 234, at P 4.

240. *Id*. at P 5.

241. Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, F.E.R.C. STATS. & REGS. ¶ 61,215, 81 Fed. Reg. 67,120 (2016), 156 F.E.R.C. ¶ 61,215 (2016), *reh'g denied*, Order No. 830-A, 158 F.E.R.C. ¶ 61,041 (2017).

242. *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event*, 161 F.E.R.C. ¶ 61,048 at P 4 (Oct. 19, 2017).

243. *Id*. at P 6.

244. *Id.* at P 9.

245. *Id.* at P 14.

and impact studies and then GIC Field Orientation for Transformers Thermal Impact Assessments.[246] The Order further assigned the additional areas of research a priority.[247]

In public comments to the Order, the Edison Electric Institute (EEI) noted concerns over the "significant scope and scale" of the project, and particularly how it would be funded.[248] Concerned that the GMD Work Plan would extend NERC authority, EEI suggested that coordination should be sought between NERC, the FERC, and the Department of Energy to determine a cost share arrangement to fund the research.[249]

The FERC also responded to comments relating to "developing a comprehensive magnetometer network," noting that the issue will be addressed as part of the Reliability Standard TPL-007-1, and comments compelling magnetometer data, noting that compelling the Electric Power Research Institute, Inc. is outside of the FERC jurisdiction.[250]

246. *Id.* at P 15.
247. 161 F.E.R.C. ¶ 61,048 at P 15.
248. *Id.* at P 18.
249. *Id.*
250. *Id.* at P 21.

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