

REPORT OF THE SYSTEM RELIABILITY, PLANNING, AND 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, 2016, through June 30, 2017.*

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* This report was prepared by Shannon Maher Bañaga, Thomas Devita, Andrew Dressel, Senrui Du, Gloria Ejekwu, Leigh Faugust, Meredith Jolivert, Ed Kichline, Shereen Jennifer Panahi, Brandon Robinson, Alan Rukin, David Schmitt, and Daniel Skees. The System Reliability, Planning, and Security Committee wishes to acknowledge the support of the full Committee in producing this report.

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I. GRID SECURITY AND CRITICAL ASSET SECURITY

A. *Ukraine Malware Discovery*

On June 12, 2017, NERC issued a statement indicating that it was aware of a “vulnerability discovered in Ukraine that has the potential to impact industrial control systems.”¹ NERC noted that, “[t]o date, there are no reported instances of the malware in North America.”² “The Electricity Information Sharing and Analysis Center (E-ISAC) also shared information” relating to the malware discovery “with industry via the E-ISAC secure portal.”³ Additionally, a public Level 1 NERC alert was developed providing additional analysis and detail regarding the discovery.⁴

The Level 1 Alert described a December 18, 2016 cyber-attack and noted that the malware was:

1. Marcus Sachs, *Statement on Ukraine Malware Discovery*, ELEC. INFO. SHARING & ANALYSIS CTR. (June 12, 2017), <http://www.nerc.com/news/Pages/Statement-on-Ukraine-Malware-Discovery.aspx>.

2. *Id.*

3. *Id.*

4. *Id.*

a development and improvement on previous cyber-attack trade craft used to attack Ukraine's electric infrastructure. Prior to the December 18, 2016 cyber-attack that leveraged this malware, Ukraine's electric infrastructure was the victim of another cyber-attack that affected approximately 225,000 customers for several hours. On December 23, 2015, three of Ukraine's 23 Oblenergos [(distribution companies)] were attacked. The coordinated attacks focused on breaker controls at three electricity distribution sites. The breakers were opened through remote access to the operations environment. The 2016 attacks on Ukraine's grid automated a lot of the actions necessary to cause the desired effect. The actors behind these cyber-attacks appear to continue developing and improving their ability to impact Ukraine's power grid.⁵

After providing additional details about the alert, "[t]he E-ISAC encourage[d] [its] members to limit privileged access and remove unnecessary privileged accounts from the ICS environment."⁶ The E-ISAC noted that "authentication should include two-factor authentication . . . [and] members should develop an understanding of the communication protocols used in their ICS environment and create a baseline of how these protocols are typically used. This base knowledge should be used to monitor network traffic for deviations. . . ."⁷ The E-ISAC noted that:

[p]roper patch management processes will also help mitigate the effectiveness of some add-on functionalities of the malware, such as the denial-of-service module. Software updates should be validated with digital hashes from the vendor. Additionally, a redundant backup and recovery strategy can mitigate the effects of the malware's data wiping functionality.⁸

B. NERC-AGA Security Information Sharing Effort

Noting the growing interdependency between the natural gas and electric sectors, NERC and the American Gas Association (AGA) launched a new information sharing partnership on April 4, 2017.⁹

The operational and security interdependency of the industries include electric utilities' need for a steady supply of gas from pipelines and gas pipelines' use of electric pumps. [While] [p]ipelines are able to operate with temporary supply disruptions . . .

5. N. AM. ELEC. RELIABILITY CORP.: *INDUSTRY ADVISORY: MODULAR TARGETING ELEC. INDUS. ASSETS IN UKR.*, <http://www.nerc.com/news/Pages/Statement-on-Ukraine-Malware-Discovery.aspx> (last visited Oct. 6, 2017).

6. *Id.*

7. *Id.*

8. *Id.*

9. Press Release, American Gas Ass'n, NERC, AGA Launch Sec. Info. Sharing Effort to Leverage Gas-Elec. Interdependency Cooperation (Apr. 4, 2017), <https://www.aga.org/news/news-releases/nerc-aga-launch-security-information-sharing-effort-leverage-gas-electric>.

[a] prolonged supply disruption could result in a loss of generation that exceeds available electricity reserves. Similarly, pipelines that rely on electric pumps may have difficulty maintaining pressure during a power disruption or sustained outage.¹⁰

“Under [this] partnership, staff from the Downstream Natural Gas Information Sharing and Analysis Center (DNG-ISAC) will join the Electricity Information Sharing and Analysis Center (E-ISAC) [] [] to improve coordination on potential security risks related to critical electricity and natural gas pipeline infrastructure.”¹¹ The goals under the partnership are to: (1) “[i]mprove security collaboration on common threat information and incident response;” (2) “[p]rovide . . . joint analysis of security concerns and events;” and (3) “[a]dvance shared processes for information sharing and situational awareness.”¹² “The E-ISAC and DNG-ISAC have agreed to use existing policies and procedures at NERC and AGA for safeguarding sensitive information under the partnership.”¹³

II. RELIABILITY COMPLIANCE, ENFORCEMENT, AND NOTICE OF PENALTY

A. *Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (Sept. 2016)*

In September 2016, NERC filed its Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (2016 TFE Report) pursuant to FERC Order 706 and Appendix 4D of the NERC Rules of Procedure (ROP).¹⁴ To prepare the report, NERC reviewed Regional Entity reports covering the calendar year immediately preceding the expiration of the version 3 Critical Infrastructure Protection (CIP) Reliability Standards (version 3).¹⁵ NERC examined the types of Covered Assets for which the Regional Entities have submitted, approved, and rejected TFEs, as well as information pertaining to the ten elements identified in Section 13 of Appendix 4D.¹⁶ Using information covering the reporting period as well as

10. *Id.*

11. *Id.*

12. *Id.*

13. *Id.*

14. Annual Report of NERC of Wide-Area Analysis of Technical Feasibility Exceptions, FERC Docket Nos. RR110-1, RR13-3 (2016) [hereinafter Wide-Area Analysis]; Order No. 706, *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 F.E.R.C. ¶ 61,040 (2008). Order 706 approved eight Critical Infrastructure Protection (CIP) Reliability Standards and directed NERC to develop a set of conditions or criteria that a Responsible Entity must follow to obtain a Technical Feasibility Exception (TFE) from specific requirements in the CIP Reliability Standards.

15. Wide-Area Analysis, *supra* note 14, at 4. TFE data for version 5 CIP Reliability Standards (version 5) (effective July 1, 2016) will likely be included in NERC’s September 2017 annual report.

16. *Id.* at 5-11. During the reporting period, “Covered Asset” was defined in Appendix 2 of the ROP as a Cyber Asset or Critical Cyber Asset that is subject to a TFE. On January 21, 2016, the Commission issued a letter order in Docket No. RR16-2-000 approving revisions to the ROP, including modifications to Appendices 2 and 4D, to ensure that the procedures for TFEs in the ROP were consistent with version 5 of the CIP Reliability Standards. See *N. Am. Elec. Reliability Corp.*, Docket No. RR16-2-000 (Jan. 21, 2016) (unpublished delegated letter order). The effective date of version 5 CIP Reliability Standards was extended to July 1, 2016. See also *Order Granting Extension of Time*, 154 F.E.R.C. ¶ 61,137 (2016). Appendix 2 of the ROP now defines the term

prior reporting periods, NERC analyzed both long-term and short-term trends to understand how the TFE program impacts risk to the reliability of the Bulk Power System (BPS).¹⁷

In the Report, NERC concluded that while the reporting period showed decreasing reliance on the risk-based TFE program, the need for TFEs would likely continue for the foreseeable future.¹⁸ Due to the infancy of the new CIP Reliability Standards, the full extent of the impact that the transition to version 5 may have on future reliance on TFEs remains undetermined.¹⁹ Overall, NERC's review concluded that the risk-based TFE program has "been [a] useful tool[] for Regional Entity auditors to review when assessing the relative risks for the systems they support."²⁰ In addition, "NERC ha[d] received no reports of inconsistency either in assessing the accuracy or validity of TFEs submitted by Responsible Entities, or in the decisions approving or rejecting TFEs."²¹

NERC's analysis under Appendix 4D revealed that 21% of U.S. entities subject to CIP version 3 have identified Critical Cyber Assets (CCAs), and have requested TFEs since the program's inception.²² As of the 2016 TFE Report date, 219 entities have active TFEs.²³ This represents a 90% decrease in the number of TFEs submitted and approved or rejected from the previous year and a "large number of terminated TFEs."²⁴ NERC attributed these trends to the transition to CIP version 5.²⁵ Nevertheless, the Report revealed program consistency with prior years in other aspects.²⁶ Among other things, "other assets" remained the leading type of Covered Asset receiving TFE approval since the program's inception.²⁷ Justifications for which approved TFEs "were submitted and approved" also remained consistent with the cumulative trend.²⁸ Additionally, and as with previous reports, Responsible Entities continue to employ multiple strategies to mitigate or compensate for the risk posed by TFEs.²⁹ "A significant portion of" these measures involved using firewalls, intrusion detection/prevention, authentication,

"Covered Asset" as "any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to" a TFE. Wide-Area Analysis, *supra* note 14, at 3 n.8.

17. Wide-Area Analysis, *supra* note 14, at 2.

18. *Id.* at 15-16.

19. *Id.*

20. *Id.* at 14.

21. Wide-Area Analysis, *supra* note 14, at 17.

22. *Id.* at 7.

23. *Id.* at 5.

24. *Id.* at 5-6.

25. *Id.* at 5.

26. Wide-Area Analysis, *supra* note 14, at 17.

27. *Id.* at 9. The Report provides examples of "other assets," such as firewalls, Intrusion Detection and Protection Systems, Intrusion Detection Systems, network wiring within Electronic Security Perimeters but outside Physical Security Perimeters, remote access controllers, and supervisory control and data acquisition (SCADA) applications). *See generally id.*

28. *Id.* at 11 (leading justifications include: (1) not technically possible; (2) operationally infeasible; or (3) precluded by technical limitations).

29. *Id.* at 12.

and system status monitoring.³⁰ These practices are expected to continue under CIP version 5.³¹

NERC's review also examined "the number[] of approved TFEs that are scheduled to reach their TFE Expiration Dates during" the next reporting period.³² "As version 5 . . . became mandatory and enforceable [immediately following the reporting period], over 80% of the TFEs that were in effect for version 3 . . . became obsolete, and [were] no longer accountable in the program."³³ Significantly, analysis of the number "of TFEs that expired or terminated during this and previous reporting periods" revealed that "no TFEs were terminated due to a material misrepresentation by the Responsible Entity as to the facts relied upon by the Regional Entity in approving the TFE [during this reporting period]."³⁴ Further, NERC found that "[a]ll eight Regional Entities reported that during the [] reporting period, there were no instances of rejection, disapproval, or termination of TFE requests where the effective date was extended past the latest date specified in . . . Appendix 4D."³⁵ These findings represent increased transparency in the submission of TFE requests across Responsible Entities.

B. Annual Compliance Monitoring and Enforcement Program Filing (Feb. 2017) and Q1-Q2 2017 Compliance Monitoring and Enforcement Program Reports (Apr. 2017 and Aug. 2017)

On February 21, 2017, NERC filed its Annual Compliance Monitoring and Enforcement Program Report (2016 Annual CMEP Filing) with FERC "on an information[al] basis."³⁶ In a petition accompanying the report, NERC proposed "enhancements to specific portions of the risk-based CMEP based on the Electric Reliability Organization (ERO) Enterprise's experience with the implementation of" the Compliance Exception (CE) and Self-Logging programs.³⁷

The 2016 Annual CMEP Report reviewed the progress of "NERC['s] and the eight Regional Entities[']" implementation of "the risk-based . . . CMEP," and "describe[d] the key activities that occurred in 2016."³⁸ NERC reported that "[i]n

30. *Id.*

31. Wide-Area Analysis, *supra* note 14, at 4.

32. *Id.* at 4.

33. *Id.* at 10.

34. *Id.* The numbers of approved TFEs still in effect as of the Report date was inhibited due to an incomplete data set resulting from the transition to version 5. The precise number will be included in NERC's 2017 annual report.

35. *Id.* at 13.

36. NERC Proposed Annual Compliance Monitoring and Enforcement Program Filing at 1, 3, FERC Docket No. RR15-2-005 (Feb. 21, 2017) [hereinafter Proposed Annual Compliance Monitoring and Enforcement Program Filing].

37. *Id.* at 3. The Commission certified NERC as the ERO in accordance with Section 215 of the Federal Power Act on July 20, 2006. *See generally N. Am. Elec. Reliability Corp.*, 116 F.E.R.C. ¶ 61,062 (2006), *reh'g denied in part and granted in part*, 117 F.E.R.C. ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009). "ERO Enterprise" refers to NERC and the eight Regional Entities.

38. Proposed Annual Compliance Monitoring and Enforcement Program Filing, *supra* note 36, at 3.

2016, CMEP activities throughout the ERO Enterprise reflected continuing implementation of the risk-based approach introduced in 2013 through the Reliability Assurance Initiative.”³⁹ Specifically, the “ERO Enterprise and industry compliance and enforcement resources were focused on risks to the [reliability of the] BPS, entity-specific risks, and serious risk noncompliance. . . .”⁴⁰ “The ERO Enterprise also continued its commitment to align core CMEP activities.”⁴¹

“Based on the results of its oversight activities,” in 2016, NERC’s report identified two proposed “enhancements to the risk-based CMEP . . . : (1) providing minimal risk Compliance Exceptions (CEs) identified through self-logging to FERC non-publicly; and (2) expanding the use of CE to include certain moderate risk noncompliance currently processed through [the] Find, Fix, Track and Report [program] (FFTs).”⁴² NERC included it would develop and submit to the Commission “[a]ny necessary Rules of Procedure changes associated with the two enhancements . . . at a later date.”⁴³

In its report, NERC proposed “to provide self-logged CE to FERC non-publicly.”⁴⁴ “The Self-Logging Program would remain limited to minimal risk non-compliance.”⁴⁵ “NERC would continue to post non-logged noncompliance pursuant to current processes.”⁴⁶ In addition, NERC proposed that

the ERO Enterprise would make two enhancements to the information it provides publicly. First, it would provide annual summaries of the noncompliance included in the logs in its Annual CMEP Report. Second, NERC would begin posting on its website a public list of registered entities admitted to the Self-Logging Program. This public list of high-performing entities would provide an additional incentive for registered entities to request admission to the program.⁴⁷

“As a second enhancement to the risk-based CMEP, NERC [proposed] to expand the CE program to allow for the resolution of certain moderate risk non-compliance.”⁴⁸ Mirroring the criteria “which [the] FERC approved for moderate risk noncompliance treated as FFTs,” NERC recommended criteria, “among other things[] the Compliance Enforcement Authority (CEA) would consider . . . to determine which moderate risk noncompliance may be eligible for CE treatment.”⁴⁹ These criteria included: “(1) the registered entity’s internal compliance program, management practices that self-identify noncompliance, and commitment to compliance; (2) mitigating factors during the pendency of the noncompliance; [] (3)

39. *Id.* at 25.

40. *Id.*

41. *Id.*

42. *Id.* at 4.

43. Proposed Annual Compliance Monitoring and Enforcement Program Filing, *supra* note 36, at 6.

44. *Id.* at 5.

45. *Id.*

46. *Id.*

47. Proposed Annual Compliance Monitoring and Enforcement Program Filing, *supra* note 36, at 5.

48. *Id.* at 5.

49. *Id.* at 5-6.

‘above and beyond’ mitigating measures;” and (4) aggravating compliance history.⁵⁰

In its 2016 Annual CMEP Filing, NERC reported that “higher-risk cases continued to be a small percentage of the overall caseload.”⁵¹ NERC found that the highest reliability risks generally stemmed from violations involving “CIP Reliability Standards, vegetation contacts, repeat conduct, and entities undergoing corporate changes.”⁵² In total, “[t]he NERC Board of Trustees Compliance Committee” approved a total of “18 Full Notices of Penalty” in 2016 and assessed total penalties in the sum of \$4,208,000.⁵³

In Q1 and Q2 2017, NERC Enforcement reviewed the risks addressed in the Full NOPs for the period from January 1, 2017 through June 30, 2017.⁵⁴ From this review emerged trends in the type of risk associated with noncompliance disposed of as Full NOPs.⁵⁵ During Q1 2017, NERC filed four Full NOPs resolving nine violations of NERC Reliability Standards, totaling \$565,000 in monetary penalties.⁵⁶ Two cases involved vegetation contacts for affiliated entities and together provided a holistic view into the parent company’s enhancements to its vegetation management programs to remediate the violations.⁵⁷ One case involved a load shedding event, which combined with a negative compliance history and the significance of the entity involved to the reliability of the area in which the event occurred, elevated the penalty amount for two moderate risk violations.⁵⁸ The last case involved the disposition of four moderate risk Operations and Planning Reliability Standard violations.⁵⁹ In this case the violations were due to a network equipment outage that caused a 75-minute loss of system monitoring.⁶⁰

In Q2 2017, NERC filed a Full NOP with a \$201,000 combined penalty resulting from a Settlement Agreement between the Western Electricity Coordinating Council (WECC) and an Unidentified Registered Entity.⁶¹ The reason NERC

50. *Id.*

51. N. AM. ELEC. RELIABILITY CORP., 2016 ERO ENTER. COMPLIANCE MONITORING & ENF’T PROGRAM ANNUAL REPORT 3 (2017) [hereinafter 2016 Annual CMEP Report].

52. *Id.*

53. *Id.*

54. NERC Full Notice of Penalty Regarding Miss. Power Co., FERC Docket No. NP17-15-000 (Feb. 28, 2017) [hereinafter NOP Miss. Power Co.]; NERC Full Notice of Penalty Regarding Tex.-N.M. Power Co., FERC Docket No. NP17-17-000 (Feb. 28, 2017) [hereinafter NOP Tex.-N.M. Power Co.]; NERC Full Notice of Penalty Regarding Elec. Power Serv. Corp. as agent for AEP Tex. N. Co., AEP Tex. Cent. Co., & Pub. Serv. Co. of Okla., FERC Docket No. NP17-18-000 (Feb. 28, 2017) [hereinafter NOP AEP]; NERC Full Notice of Penalty Regarding Ala. Power Co., FERC Docket No. NP17-19-000 (Feb. 28, 2017) [hereinafter NOP Ala. Power Co.]; NERC Full Notice of Penalty Regarding Unidentified Registered Entity, FERC Docket No. NP17-21-000 (April 27, 2017) [hereinafter NOP URE].

55. *See generally* NOP Miss. Power Co., *supra* note 54; NOP Tex.-N.M. Power Co., *supra* note 54; NOP AEP, *supra* note 54; NOP Ala. Power Co., *supra* note 54; NOP URE, *supra* note 54.

56. NOP Miss. Power Co., *supra* note 54, at 1-2; NOP Tex.-N.M. Power Co., *supra* note 54, at 1, 3; NOP AEP, *supra* note 54, at 1-2; NOP Ala. Power Co., *supra* note 54, at 1-3.

57. *See generally* NOP Miss. Power Co., *supra* note 54; *see also* NOP Ala. Power Co., *supra* note 54.

58. NOP AEP, *supra* note 54, at 2-5.

59. NOP Tex.-N.M. Power Co., *supra* note 54, at 3-6.

60. *Id.* at 4.

61. NOP URE, *supra* note 54, at 2.

treated the case as a Full NOP, despite it consisting of two moderate risk CIP violations, was to highlight Western Electricity Coordinating Council's (WECC) engagement with a registered entity regarding its internal controls.⁶² WECC increased its interaction with the entity to enhance the registered entity's culture of compliance, reliability, and security.⁶³ Although the violations were self-reported, WECC did not credit the URE for self-reporting because the report was made a year after the discovery of a violation.⁶⁴

III. RELIABILITY REPORTS AND ASSESSMENTS

A. NERC's 2016 Long Term Reliability Assessment (Dec. 2016)

On December 15, 2016, NERC issued the 2016 Long-Term Reliability Assessment (LTRA).⁶⁵ The LTRA is an annual report compiled by NERC's Reliability Assessment and Performance Analysis Group with the "primary objective [of] assess[ing] resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years."⁶⁶ The LTRA found sufficient reserve margins across the North American BPS for the next five years but raised concerns about the changing resource mix, plant retirements, distributed energy resources, and natural gas reliance.⁶⁷

NERC's 2016 LTRA analyzes risk among six focus areas affecting, or anticipated to affect, reliability over the next decade, including: (1) resource adequacy, (2) single fuel dependency, (3) nuclear uncertainty, (4) probabilistic analysis, (5) essential reliability services, and (6) distributed energy resources (DERs).⁶⁸ The resource adequacy assessments examine "a reserve margin analysis and the study of emerging reliability issues that can impact generation and demand projections."⁶⁹ Single fuel dependency highlights the reliability impacts of increased dependence on a single fuel, natural gas, which increases system vulnerabilities, "particularly during extreme weather."⁷⁰ Nuclear uncertainty is assessed as a risk because of increased retirements including "unconfirmed nuclear retirements [which] create uncertainty around local transmission adequacy and the ability to plan for future resource and demand needs."⁷¹ NERC has increased the use of probabilistic analysis to better capture the performance characteristics of a changing electric grid.⁷² NERC is in the process of "developing sufficiency guidelines

62. *See generally id.* at 3-5.

63. *Id.* at 4.

64. *Id.* at 5.

65. N. AM. ELEC. RELIABILITY CORP.: 2016 LONG-TERM RELIABILITY ASSESSMENT, <http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf> (last visited Oct. 6, 2017) [hereinafter 2016 LTRA].

66. *Id.* at vi.

67. *Id.* at ix.

68. *Id.* at vii-viii.

69. *Id.* at vii.

70. 2016 LTRA, *supra* note 65, at vii.

71. *Id.* at viii.

72. *Id.* at 23.

in order to establish requisite levels of [essential reliability services].”⁷³ Finally, NERC investigated DERs to consider the reliability impacts of DERs because of the “lack [of] sufficient visibility and operational control of these resources.”⁷⁴

NERC also developed three recommendations through its stakeholder process “to alleviate the potential impacts of the [identified] reliability issues” listed above.⁷⁵ Specifically, NERC stated that (1) “[r]egulators and legislators should evaluate the changes occurring on the BPS,” (2) “system planners and operators should evaluate the potential effects of an increased reliance on natural gas,” and (3) “[r]egulators and legislators should consider the uncertainties in resource retirements and resource mix changes . . . including . . . curtailments[] and transmission constraints that can manifest if [essential reliability services] are not maintained.”⁷⁶

B. NERC’s Distributed Energy Resources Report (Feb. 2017)

In February 2017, NERC’s Distributed Energy Resources Task Force issued a report entitled “Distributed Energy Resources: Connection Modeling and Reliability Considerations.”⁷⁷ The North American generation resource mix is changing from larger synchronous sources to “a more diverse fleet of smaller . . . resources with varying generation characteristics.”⁷⁸ The report did not compare the capability of DER versus conventional resources, but rather discussed potential reliability risks and mitigation approaches for increased DER on the BPS.⁷⁹ Among other things, the report offered a formal definition of DER, addressed BPS “reliability considerations, modeling, and DER ride-through response given an event grid disturbance,” listed NERC standards and reports that address or are impacted by DER, and offered several recommendations.⁸⁰

The report defines DER as “any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).”⁸¹ As defined, the report states, “DER include any non-BES resource (e.g.[,] generating unit, multiple generating units at a single location, energy storage facility, micro-grid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only.”⁸² This includes distributed generation, behind-the-meter generation, energy storage facilities, DER aggregation, micro-grids, co-generation, and

73. *Id.* at viii.

74. *Id.*

75. 2016 LTRA, *supra* note 65, at ix.

76. *Id.*

77. N. AM. ELEC. RELIABILITY CORP.: DISTRIBUTED ENERGY RESOURCES: CONNECTION MODELING AND RELIABILITY CONSIDERATIONS, http://www.nerc.com/comm/other/essntrlrbltysrvdstskfcdl/distributed_energy_resources_report.pdf (last visited Oct. 6, 2017) [hereinafter Distributed Energy Resources].

78. *Id.* at vi.

79. *Id.* at iv, vi.

80. *Id.* at vi.

81. *Id.* at 1.

82. *Id.*

“[e]mergency, [s]tand-by, or [b]ack-up generation.”⁸³ “Demand side management (DSM) resources which do not produce electricity are not included in the definition and [are] outside the [scope] of th[e] report.”⁸⁴ The report notes that DER, as defined in the report, “are generally interconnected to a distribution provider’s electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). . . . [Thus,] the effect of aggregated DER is not fully represented in BPS models and operating tools.”⁸⁵ However, the report stated that “DSM activities can have impacts at the [transmission-distribution] interface that overlap and interact with those of DER,” and suggested that “the task force recommend[] future consideration of DSM in the DER definition and how the [report’s] recommendations [could] be applied to DER and DSM resources in a unified way.”⁸⁶

In examining reliability considerations, the report focused on several key areas. For example, the report states that “data on installed and projected DER units is needed for reliability modeling purposes.”⁸⁷ In addition, “[r]amping and balancing activities may become more challenging for regions with high levels of DER and variable energy resources (VER).”⁸⁸ The report further states that “modern DER units will be capable of providing [essential reliability services] and supporting BPS reliability,” thus presenting “an opportunity to enhance BPS performance when applied in a thoughtful and practical manner.”⁸⁹

The report includes several data requirements “around appropriate modeling for (1) steady-state power flow and short-circuit studies, and (2) dynamic disturbance ride-through and transient stability studies for BPS planning.”⁹⁰ The report next addressed characteristics of nonsynchronous DER, discussing how voltage ride-through and frequency performance of DER is not currently coordinated with BPS requirements — the report thus states that an event causing a large amount of DER to isolate from the grid could result in unpredicted BPS behavior.⁹¹ The report also discussed Rule 21 of the California Public Utilities Commission (CPUC), which “regulates the largest rollout of DER in North America.”⁹² The “CPUC is in the process of implementing new technical standards for the DER system that are intended to go beyond [safety] and hazard issues and ‘establish programmable functions’ . . . to support power system operations.”⁹³ In Chapter

83. Distributed Energy Resources, *supra* note 77, at 1-2. Each of these terms is also defined in the report.

84. *Id.* at 2.

85. *Id.*

86. *Id.*

87. *Id.* at 4.

88. Distributed Energy Resources, *supra* note 77, at 4. (“VER [] are now required to ride through disturbances, to provide reliability services, and to have active power management capability to respond to dispatch or automatic generation control (AGC) signals”).

89. *Id.*

90. *Id.* at 6. This included data requirements and information sharing at the transmission-distribution interface, and DER modeling for BPS planning and operations. The report did not include distribution system aspects, BPS small-signal stability, and BPS operational aspects such as flexibility and ramping.

91. *Id.* at 16.

92. *Id.* at 20.

93. Distributed Energy Resources, *supra* note 77, at 20.

5, the report addressed the previous work of the NERC Integrating Variable Generation Task Force (IVGTF), who had expressed particular concern about “the lack of disturbance tolerance, which entails voltage ride through (VRT) and frequency ride through (FRT) capability.”⁹⁴ Since the IVGTF’s report “in December 2014, efforts have commenced to harmonize the PRC-024-2 VRT and FRT requirements with IEEE 1547,” and the report noted that it appeared that planned updates to 1547 “will respect PRC-024-2 voltage and frequency ride-through requirements.”⁹⁵

Finally, the report reviewed existing NERC standards and concluded there is no need for the development of additional standards to address the increasing DER penetration; however, it “recommend[ed] that DP [(Distribution Providers)] be added as an applicable entity in MOD-032, replacing the Load-Serving Entity,” or LSE function.⁹⁶ The report stated that “[c]urrent standards (TOP-003-3, IRO-010-2, and MOD-032-1) provide broad authority for system operators and transmission planners to obtain the information needed for models and reliability assessments,” thus providing them with “the ability to collect pertinent information [] related to” the impact of DER on the BES.⁹⁷ However, the report “recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DER at the interface.”⁹⁸

In conclusion, the report lists seven recommendations for additional efforts that should be a part of ongoing efforts by the ERS working group (ERSWG): **(1) Guidelines:** a set of guidelines to assist owners/operators in modeling and assessments for the impact of DER, and the addition of DP “as an applicable entity in MOD-032;” **(2) Data Sharing:** near-term sharing of information across the transmission-distribution interface, with additional consideration in the future “for stability, protection, forecasting, reactive needs, and real time estimates for operating needs;” **(3) Modeling:** explicit modeling of load and DER “in **(a)** steady-state power flow and short-circuit studies, and **(b)** dynamic disturbance ride-through studies and transient stability studies for BPS planning with a level of detail . . . appropriate to represent the aggregate impact of DER on the modeling results over a 5 to 10 year planning horizon;” **(4) Dynamic Models:** making available dynamic models for different DER technologies for use in “model[ing] the evolving interconnection requirements and related performance requirements” (e.g., WECC’s simplified distributed PV model); **(5) Coordination:** “A coordinated effort by distribution and transmission entities . . . to determine appropriate use of future DER capabilities (such as settings available under proposed IEEE 1547 revisions);” **(6) Definitions:** Further examination “to determine whether DSM should be included in the DER definition and [whether] the DER definition should be added to the

94. *Id.* at 23.

95. *Id.* at 24.

96. *Id.* at 25.

97. *Id.* at 25-26 (“the necessary DER information can generally be in somewhat aggregated form, but with enough detail to allow accurate modeling . . . at the transmission-distribution [] interface. This level of detail also extends to forecasting and operati[onal] issues”).

98. Distributed Energy Resources, *supra* note 77, at 26.

NERC glossary and/or NERC functional model;” and **(7) Industry Collaboration:** Collaboration between the industry and “vendors of power system simulation software and DER product vendors to continuously enhance models for DER representation in BPS planning studies.”⁹⁹ Finally, the report includes Appendices which describe typical DER connections (Appendix A), describe how operations and long-term planning in light of DER are addressed in California (Appendix B), list the NERC standards reviewed by the DER task force (Appendix C), and outline the relationship between DSM Resources and DER at the transmission-distribution interface (Appendix D).¹⁰⁰

C. State of Reliability 2017 (June 2017)

In June of 2017, NERC issued its 2017 State of Reliability Report.¹⁰¹ The 208-page report addressed the performance of the BPS in 2016 as compared to previous years, focusing on the ERO Reliability Risk Priorities that were identified by NERC’s Reliability Issues Steering Committee (RISC) and accepted by the NERC Board of Trustees in November 2016.¹⁰²

The report highlighted the following key findings: (1) there were “No Category 4 or 5 events in 2016;” (2) the rate of Protection system misoperations “continues to decline, but remains a priority;” (3) “Frequency response shows improvement, but requires continued focus;” (4) “Cyber and physical security risk increases despite no loss of load events;” (5) “Transmission outages caused by human error show a slight increase;” and (6) “BPS resiliency to severe weather continues to improve.”¹⁰³

Accompanying each key finding were recommendations, many of which focused on expanding outreach and collaboration among industry, vendors, NERC, and the public sector.¹⁰⁴

The report began by highlighting reliability actions taken in 2016 to mitigate strategic reliability risk as well as events that occurred that could offer further insight – it identified as high reliability profiles the following issues: (1) the changing resource mix; (2) BPS planning; (3) resource adequacy performance; and (4) cyber security vulnerabilities.¹⁰⁵ In addition, the report listed the original sixteen reliability metrics used in past reports, and “show[ed] changes to BPS reliability observed in 2016 when compared to previous years” with trending results.¹⁰⁶ Issues highlighted by the report include: (1) essential reliability services (including primary frequency response and voltage support); (2) “the increasing risk of fuel disruption impacts on generator availability from the increased dependence of

99. *Id.* at 27.

100. *Id.* at 28-39.

101. N. AM. ELEC. RELIABILITY CORP., STATE OF RELIABILITY 2017, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf (last visited Oct. 6, 2017) [hereinafter State of Reliability 2017].

102. *Id.* at vi.

103. *Id.*

104. *Id.* at 1-6.

105. *Id.* at 7.

106. State of Reliability 2017, *supra* note 101, at vii.

electric generation and natural gas infrastructure as a single point of disruption;” (3) “renewable penetration and distributed energy resources” (including the “unplanned loss of renewable generation”); and (4) grid security (detailing efforts by E-ISAC, including the DOE/NERC/E-ISAC partnership involving CRISP).¹⁰⁷

“While there were no reportable cyber security incidents during . . . 2016, and therefore [no events] that caused loss of [l]oad,” the report recognized that “this does not . . . suggest that [cybersecurity risk] is low,” and the report noted that “the NERC Critical Infrastructure Protection Committee (CIPC) and NERC’s [] (E-ISAC) have developed a roadmap for future metrics development, including refining the initial set of metrics that are based on operational experience.”¹⁰⁸

The report reviewed recommendations from previous reports that have been completed, counting 41 actionable recommendations over the last six years of reporting, of which 34 have been completed.¹⁰⁹ It also addressed ongoing recommendations from previous years and actions taken to date.¹¹⁰

IV. NERC BUSINESS PLAN AND BUDGET

A. Annual Budget Filing and Quarterly True-up Filings

On August 23, 2016, in Docket No. RR16-6-000, NERC asked the Commission to approve the 2017 business plans and budgets for NERC, the Regional Entities, and “the Western Interconnection Regional Advisory Body (WIRAB).”¹¹¹ NERC asked that the Commission act on these proposals by November 2, 2016, to enable billings to LSEs to begin on or about January 1, 2017.¹¹² Key facets of the budget proposal included the following:

- NERC proposed a 3.6% budget increase in 2017.¹¹³
- The total NERC assessments to LSEs would be approximately \$59.9 million.¹¹⁴ This included funding from other sources, such as penalty assessments.¹¹⁵
- NERC did not propose an increase in full-time employees (FTEs).¹¹⁶ Instead, proposed FTE staffing was 2.5 FTEs lower than in the 2016 budget.¹¹⁷

107. *Id.* at 7-11.

108. *Id.* at vii. This roadmap is discussed in further detail in Appendix G of the report.

109. *Id.* at 65.

110. State of Reliability 2017, *supra* note 101, at 65.

111. Request of NERC for Acceptance of its 2017 Business Plan and Budget and the 2017 Budget Plans and Budgets of Regional Entities and for Approval of Proposed Assessments to Fund Budgets 1, FERC Docket No. RR16-6-000 (Aug. 23, 2016) [hereinafter Request of NERC].

112. *Id.* at 2.

113. *Id.* at 8.

114. *Id.* at 10.

115. *Id.* at 10-11.

116. Request of NERC, *supra* note 111, at 8.

117. *Id.*

- NERC’s consulting and contracting expenses were proposed to increase to approximately \$3.4 million, mostly due to IT expenses and for ERO Application Development and Support and Applications Enhancement.¹¹⁸
- The Regional Entity with the highest assessments to Load-Serving Entities (LSEs) (including NERC and Regional costs) was WECC.¹¹⁹
- The Region with the lowest assessments to Load-Serving Entities (LSEs) (including NERC and Regional costs) was FRCC.¹²⁰

On September 23, 2016, NERC filed a supplemental clarification on the proposed 2017 budget for the NPCC and RF Regional Entities.¹²¹ NERC clarified that “[i]n approving NPCC’s 2017 Business Plan and Budget, [it] did not approve any special or separate allocation process for the allocation of costs” for NPCC (i) “sub-regional reliability assessment costs in response to U.S. only regulatory initiatives” or (ii) 2017 activities related to NPCC’s “Reliability Assessment and Performance Analysis program in any manner other than on the basis of Net Energy for Load.”¹²² NERC also clarified that “ReliabilityFirst used its Penalty collections for the 12 months ended June 30, 2015, solely to reduce 2016 assessments[,] and [was] proposing to use its Penalty collections for the 12 months ended June 30, 2016, solely to reduce 2017 assessments.”¹²³

WIRAB filed supporting comments in that docket urging the Commission to find that “all of the proposed activities [are] eligible and appropriate for funding under [s]ection 215 of the Federal Power Act.”¹²⁴ According to WIRAB’s comments, which focused on the WECC Region, “[t]he changing resource mix in the West is forcing WECC to examine and study emerging reliability challenges. Robust strategic planning by WECC is an essential process to be able to cost-effectively address these reliability challenges.”¹²⁵

On October 20, 2016, FERC issued an order approving NERC’s “2017 business plans and budgets” for itself, the Regional Entities, and WIRAB.¹²⁶ The Commission found that the NERC budget was reasonable and equitably allocates costs among end-users.¹²⁷ The Commission also approved NERC’s request to allocate \$500,000 from reliability penalties to its assessment stabilization reserve.¹²⁸

118. *Id.* at 68-69.

119. *Id.* at 31.

120. *Id.*

121. *See generally* Supplemental Clarification Filing of NERC Concerning Proposed 2017 Business Plans and Budgets of Northeast Power Coordinating Council, Inc. and ReliabilityFirst Corp., FERC Docket No. RR16-6-000 (Sept. 23, 2016).

122. *Id.* at 2.

123. *Id.* at 3.

124. Advice of WIRAB 4, FERC Docket No. RR16-6-000 (Sept. 13, 2016).

125. *Id.*

126. *N. Am. Elec. Reliability Corp.*, 157 F.E.R.C. ¶ 61,043 at P 1 (2017).

127. *Id.* at P 17.

128. *Id.*

In response to its ongoing obligation to report budget-to-actual variance information in accordance with the settlement agreement approved by the Commission following a 2012 audit of NERC, *North American Electric Reliability Corp.*, 142 F.E.R.C. ¶ 61,042 (2013), NERC continues to file these reports on a quarterly basis in Docket No. FA11-21-000.¹²⁹

On August 15, 2016, NERC submitted its budget-to-actual variance report for the second quarter of 2016.¹³⁰ In the filing, NERC explained that the Compliance Assurance Program was projected “to be [\$839,000] less than budgeted . . . primarily due to lower than expected Personnel Expenses [created by] staff vacancies.”¹³¹ NERC also expected that Reliability Assessments and Performance Analysis Program expenses would “be \$1.1 [million] more than budgeted, primarily due to the transfer of [additional] positions from the Compliance Assurance Program” to assist in reliability reports, BES exception resolution, and the analysis of historical events.¹³²

On November 14, 2016, NERC submitted its budget-to-actual variance report for the third quarter of 2016.¹³³ NERC stated that “[t]hrough September 30, 2016, [it] was \$2.5 [million] (4.9%) under its expense and fixed asset budget.”¹³⁴ Excluding funds related to the Cyber Risk Information Sharing Program (CRISP), NERC was \$1.9 million, or 4.1%, under budget.¹³⁵ The changes were primarily due to E-ISAC projects (i.e., portal improvements, machine to machine communications, etc.), data analysis software, webTADS, and IT contract support.¹³⁶ However, overall “NERC [was] projecting to be [] \$926 [thousand] . . . over budget at year-end . . . due to higher . . . projected costs related to the CRISP program.”¹³⁷

On May 15, 2017, NERC submitted its “budget-to-actual variance” report “for the first quarter of 2017.”¹³⁸ NERC stated that:

Actual 2017 direct expenses plus net fixed asset expenditures for the Compliance Analysis, Certification and Registration Program are projected at year end to be [\$538,000] more than budgeted, primarily due to the allocation of additional staff resources to support program activities, and costs related to design of a new entity registration database.¹³⁹

129. *N. Am. Elec. Reliability Corp.*, 142 F.E.R.C. ¶ 61,042 at P 14 (2013).

130. Compliance Filing of NERC 1, FERC Docket No. FA11-21-000 (Aug. 15, 2016).

131. *Id.* at 3.

132. *Id.* at 4.

133. Compliance Filing of NERC, *supra* note 130, at 1.

134. *Id.* at 7.

135. *Id.*

136. *Id.*

137. *Id.*

138. Compliance Filing of NERC, *supra* note 130, at 1.

139. *Id.* at 2.

Additionally, “[a]ctual 2017 direct expenses plus net fixed asset expenditures for the Information Technology department are projected to be [\$575,000] under budget.”¹⁴⁰

On May 30, 2017, in Docket No. RR17-4, NERC submitted “comparisons of actual to budgeted costs for the year 2016 for NERC and . . . Regional Entities.”¹⁴¹ This report provided a lengthy list of the “recurring drivers of actual cost-to-budget variances [among] NERC and the Regional Entities;” including an “inability to fill budgeted positions,” the use of consultants to fill open positions, lower than expected CMEP expenses due to changes in that program, including risk-based compliance monitoring, and reductions in travel costs due to the use of virtual meeting capabilities.¹⁴² Ultimately, NERC’s own actual costs were within \$3,000 of its budgeted costs for 2016.¹⁴³

V. RELIABILITY STANDARDS

A. Supplemental Information for Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards BAL-005-1 and FAC-001-3

On June 14, 2016, NERC submitted its supplemental petition for approval of two “proposed reliability standards[,] BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements).”¹⁴⁴ NERC provided supplemental information explaining how Reliability Standard BAL-005-1 “support[s] the proposed retirement of Requirement R15 of Reliability Standard BAL-005-0.2b” (Automatic Generation Control).¹⁴⁵ “BAL-005-1 Mapping Document . . . provides that Requirements in Reliability Standard EOP-008-1 and the performance obligations in Requirement R3 of proposed Reliability Standard BAL-005-1 address the reliability objective of Reliability Standard BAL-005-0.2b, Requirement R15.”¹⁴⁶

On September 22, 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) “propos[ing] to approve Reliability Standard BAL-005-1 [] and FAC-001-3.”¹⁴⁷ FERC also

s[ought] comment from NERC and other interested entities regarding the retirement of Requirement R15 of Reliability Standard BAL-005-0.2b, which requires responsible entities to maintain and periodically test backup power supplies at primary control

140. *Id.* at 3.

141. Report of NERC for Comparisons of Budgeted to Actual Costs for 2016 1, FERC Docket No. RR17-4-00 (May 15, 2017).

142. *Id.* at 7.

143. *See generally id.*

144. Supplemental Information for Petition for Approval of Proposed Reliability Standards BAL-005-1 and FAC-001-3 1, FERC Docket No. RM16-13-000 (June 14, 2016).

145. *Id.*

146. *Id.*

147. Notice of Proposed Rulemaking, *Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards*, 156 F.E.R.C. ¶ 61,210 at P 1 (2016).

centers and other critical locations. Depending on the explanation received in the comments, the Commission may issue a directive in the final rule requiring NERC to restore this requirement through the standards development process.¹⁴⁸

On November 28, 2016, NERC submitted comments in response to the NOPR.¹⁴⁹ NERC supported Approval of NERC's Proposals because they "would enhance reliability and improve calculation of Reporting Area Control Error ('ACE')," and "proposed BAL-005-1 and existing EOP-008-1 are broader and duplicative of Requirement R15, supporting retirement of the requirement consistent with IERP general recommendations."¹⁵⁰

B. Supplemental Information of the North American Electric Reliability Corporation for Proposed Reliability Standard TPL-007-1

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 (Transmission System Planned Performance for Geomagnetic Disturbance Events)" and the related text.¹⁵¹ "[P]roposed Reliability Standard TPL-007-1 represents a state of the art approach to addressing the reliability risks posed by geomagnetic disturbances [(GMDs)] to the [BPS], a highly complex area in which industry and scientific understanding continues to evolve."¹⁵²

On September 22, 2016, FERC issued Order No. 830, approving Reliability Standard TPL-007-1.¹⁵³ In Order No. 830, FERC

[D]irect[ed] NERC to develop modifications . . . (1) to [revise] the benchmark GMD event definition set forth in . . . Reliability Standard TPL-007-1 . . . (2) to require the collection of necessary geomagnetically induced current [(GIC)] monitoring and magnetometer data and to make such data publicly available, and (3) to include a one-year deadline for the [completion] of corrective action plans and two and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively. The Commission also direct[ed] NERC to submit a work plan [(GMD research work plan)] and . . . one or more informational filings that address specific GMD-related research areas.¹⁵⁴

C. Petition of North American Electric Reliability Corporation for Approval of

148. *Id.* at P 25.

149. Comments in Response to Notice of Proposed Rulemaking, FERC Docket No. RM16-13-000 (Nov. 28, 2016).

150. *Id.* at 3-4.

151. Supplemental Information for Proposed Reliability Standard TPL-007-1 1, FERC Docket No. RM15-11-000 (June 28, 2016).

152. *Id.*

153. Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 F.E.R.C. ¶ 61,215 at P 1 (2016).

154. *Id.* at P 2.

Reliability Standard PRC-012-2

On August 5, 2016, NERC filed a petition for approval of proposed Reliability Standard PRC-012-2 (Remedial Action Schemes).¹⁵⁵ Specifically, the proposed Reliability Standard PRC-012-2 consists of nine Requirements: (i) three Requirements obligating the Reliability Coordinator (RC) to engage in a Remedial Action Schemes (RAS) review process (Requirements R1, R2, and R3); (ii) one Requirement mandating the Planning Coordinator “(PC) to engage in a periodic review of each RAS (Requirement R4);” (iii) one Requirement ensuring that the RAS-entity continuously reviews its RAS upon operation or misoperation (Requirement R5); (iv) two Requirements enacting a process for RAS-entities to address issues with each RAS identified by the RC in its RAS review (Requirements R6 and R7); (v) one Requirement obligating the RAS-entity to perform a periodic functional test for each of its RAS (Requirement R8); and (vi) one Requirement mandating the RC to establish a RAS database (Requirement R9).¹⁵⁶ This Reliability Standard “removes ambiguity in NERC’s original ‘fill-in-the-blank’ standard by assigning responsibility to appropriate functional entities . . . [and] also streamlines and consolidates the ‘piecemeal’ RAS standards into one clear, effective Reliability Standard.”¹⁵⁷ Further, “[t]he proposed standard imposes more focused review requirements on RAS that have greater [Bulk Electric System] reliability impact and unique design.”¹⁵⁸

On January 19, 2017, FERC issued a NOPR proposed to approve Reliability Standard PRC-012-2 and proposing to direct NERC to submit “clarifying comments addressing ‘limited impact’ RAS.”¹⁵⁹ On April 10, 2017, NERC submitted comments in response to the NOPR.¹⁶⁰ In its comments, “NERC support[ed] the Commission’s proposal to approve the proposed Reliability Standard and urge[d] the Commission to approve the proposed Reliability Standard without directing modifications.”¹⁶¹

D. Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard COM-001-3

On August 15, 2016, NERC filed a petition for approval of proposed Reliability Standard COM-001-3 (Communications) with the FERC.¹⁶²

155. Petition for Approval of Reliability Standard PRC-012-2, FERC Docket No. RM16-20-000 (Aug. 5, 2016).

156. *Id.* at 14-15.

157. *Id.* at 3.

158. *Id.* at 5.

159. Notice of Proposed Rulemaking, *Remedial Action Schemes Reliability Standard*, 158 F.E.R.C. ¶ 61,042 at P 1 (2017).

160. Comments in Response to Notice of Proposed Rulemaking, FERC Docket No. RM16-20-000 (Apr. 10, 2017).

161. *Id.* at 1.

162. Petition for Approval of Proposed Reliability Standard COM-001-3, FERC Docket No. RD16-9-000 (Aug. 15, 2016).

COM-001-3 [is designed to reflect] revisions developed under Project 2015-07 Internal Communications Capabilities, in compliance with the Commission's directive in Order No. 808 that NERC, "develop modifications to COM-001-2, or to develop a new standard, to address the Commission's concerns regarding ensuring the adequacy of internal communications capability whenever internal communications could directly affect the reliable operation of the Bulk-Power System."¹⁶³

"The standard applies to Transmission Operators, Balancing Authorities, Reliability Coordinators, Distribution Providers, and Generator Operators."¹⁶⁴ On October 28, 2016, the FERC issued a letter order approving NERC's proposed Reliability Standard COM-001-3.¹⁶⁵

E. Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-027-1 and PER-006-1 and Retirement of PRC-001-1.1(ii)

On September 2, 2016, NERC petitioned for approval of proposed Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance during Faults) and PER-006-1 (Specific Training for Personnel).¹⁶⁶

Proposed Reliability Standard PRC-027-1 provides a . . . set of Requirements that obligate . . . entities to (1) implement a process for establishing and coordinating new or revised Protection System settings[,] and (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure the Protection Systems continue to operate in their intended sequence.¹⁶⁷

"The reliable and coordinated operation of Protection Systems is essential to [BPS] reliability" because (1) "Protection Systems help maintain reliability by isolating faulted equipment, thereby reducing the risk of instability or Cascading, and leaving the remainder of the BPS operational and more capable of withstanding a future Contingency," and (2) "the functions, settings, and limitations of Protection Systems are recognized and integrated in deriving System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs)."¹⁶⁸ Proposed Reliability Standard PER-006-1 "provide[s] for formal training requirements for Generator Operators, Transmission Operators, and Balancing Authorities on Protection Systems and [Remedial Action Schemes]."¹⁶⁹ NERC also filed a petition for retirement of PRC-001-1.1(ii), as "[t]he Requirements in PRC-001-1.1(ii) are being replaced by proposed Reliability Standards PRC-027-1 and PER-

163. *Id.* at 1.

164. *Id.* at 10.

165. Letter Order, Petition for Approval of Proposed Reliability Standard, FERC Docket No. RD16-9-00 (Oct. 28, 2016).

166. Petition for Approval of Proposed Reliability Standards PRC-027-1 and PER-006-1 and Retirement of PRC-001-1.1(ii), FERC Docket No. RM16-22-000 (Sep. 2, 2016).

167. *Id.* at 26.

168. *Id.* at 2-3.

169. *Id.* at 12.

006-1 and the proposed definitions, or are addressed by Reliability Standards approved by the Commission since the effective date of PRC-001-1.”¹⁷⁰

F. Petition of the North American Electric Reliability Corporation for Retirement of Reliability Standard BAL-004-0

On November 10, 2016, NERC submitted its petition for retirement of Reliability Standard BAL-004-0 (Time Error Correction).¹⁷¹ NERC stated that “Reliability Standard BAL-004-0 has become redundant and ineffective for supporting reliability of the [BPS], with more recent Reliability Standards managing continued adherence to frequency approximating 60 Hertz over long-term averages.”¹⁷² NERC’s proposal was conditioned upon retirement of Energy Standard Board (NAESB) WEQ-006 Manual Time Error Correction Business Practice Standard (NAESB WEQ-006) “to avoid uncoordinated manual TEC.”¹⁷³ On January 18, 2017, FERC issued a letter order approving the retirement of Reliability Standard BAL-004-0.¹⁷⁴

G. Petition of the North American Electric Reliability Corporation for Approval of Interpretation of Reliability Standard CIP-002-5.1a

On November 28, 2016, NERC submitted a petition to FERC seeking approval of an interpretation of Reliability Standard CIP-002-5.1a (Cyber Security — BES Cyber System Categorization).¹⁷⁵

The proposed interpretation provides that: (1) the phrase ‘shared BES Cyber Systems’ in Criterion 2.1 refers to discrete BES Cyber Systems that are shared by multiple generation units; and (2) the evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System.¹⁷⁶

On December 27, 2016, FERC issued a letter order approving the interpretation of Reliability Standard CIP-002-5.1a.¹⁷⁷

H. Petition of the North American Electric Reliability Corporation for Approval

170. *Id.* at 3.

171. Petition for Retirement of Reliability Standard BAL-004-0, FERC Docket No. RD17-1-000 (Nov. 10, 2016).

172. *Id.* at 1.

173. *Id.* at 3.

174. Letter Order, Petition for Approval of Currently-Effective Reliability Standard BAL-004-0, FERC Docket No. RD17-1-000 (Jan. 18, 2017).

175. Petition for Approval of Interpretation of Reliability Standard CIP-002-5.1a, FERC Docket No. RD17-2-000 (Nov. 28, 2016).

176. *Id.* at 5.

177. Letter Order, Interpretation of Reliability Standard CIP-002-5.1 2, FERC Docket No. 17-2-000 (Dec. 27, 2016).

of Proposed Reliability Standard CIP-003-7

On March 3, 2017, NERC filed a petition for approval of proposed Reliability Standard CIP-003-7 (Cyber Security – Security Management Controls).¹⁷⁸

The modifications in proposed Reliability Standard CIP-003-7 improve upon the existing protections applicable to low impact BES Cyber Systems . . . by: (1) clarifying the electronic access control requirements applicable to low impact BES Cyber Systems; (2) adding requirements related to the protection of transient electronic devices used for low impact BES Cyber Systems; and (3) requiring Responsible Entities to have a documented cyber security policy related to declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems.¹⁷⁹

I. Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards IRO-002-5 and TOP-001-4

On March 6, 2017, NERC submitted its petition for approval of proposed Reliability Standards IRO-002-5 (Reliability Coordination – Monitoring and Analysis) and TOP-001-4 (Transmission Operations).¹⁸⁰ “Proposed Reliability Standards TOP-001-4 and IRO-002-5 build upon the improvements made in the prior versions of [Reliability] Standards.”¹⁸¹ “[P]roposed TOP-001-4 Requirement R10 has been revised to require the Transmission Operator to monitor non-BES facilities for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area.”¹⁸²

Proposed TOP-001-4 has been further revised to require that the Transmission Operator’s and Balancing Authority’s data exchange capabilities for the exchange of Real-time data needed for Real-time monitoring and analysis have redundant and diversely routed data exchange infrastructure within the entity’s primary Control Center and that these capabilities be tested for redundant functionality on a regular basis.¹⁸³

Proposed Reliability Standard IRO-002-5 contains similar provisions to clarify the Reliability Coordinators.¹⁸⁴ “These modifications . . . help support reliable operations by preventing a single point of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data used by operators

178. Petition for Approval of Proposed Reliability Standard CIP-003-7, FERC Docket No. RM17-11-000 (Mar. 3, 2017).

179. *Id.* at 3.

180. Petition for Approval of Proposed Reliability Standards IRO-002-5 and TOP-001-4, *N. Am. Elec. Reliability Corp.*, No. RD17-4-000 (Mar. 6, 2017).

181. *Id.* at 3.

182. *Id.*

183. *Id.*

184. *Id.* at 3-4.

to monitor and control the BES.”¹⁸⁵ On April 17, 2017, FERC issued a letter order approving the Reliability Standards IRO-002-5 and TOP-001-4.¹⁸⁶

J. Joint Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Proposed Regional Reliability Standard VAR-501-WECC-3

On March 10, 2017, NERC and WECC submitted to the FERC a joint petition for the approval of proposed Regional Reliability Standard VAR-501-WECC-3 – Power System Stabilizer (PSS).¹⁸⁷ The proposed Regional Reliability Standard VAR-501-WECC-3 includes requirements that would “ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions by establishing the performance criteria for power system stabilizers.”¹⁸⁸ It “improves upon the existing standard by (1) focusing the in-service requirement on performance of the power system stabilizers . . . , (2) incorporating the power system stabilizer policies and guidelines into a mandatory standard, and (3) reducing administrative requirements with little benefit to reliability.”¹⁸⁹ On April 28, 2017, the FERC issued a letter order approving the proposed regional Reliability Standard VAR-501-WECC-3.¹⁹⁰

K. Petition of the North American Electric Reliability Corporation for Approval of Proposed Emergency Operations Reliability Standards

On March 27, 2017, NERC filed a petition with FERC requesting approval of proposed Emergency Operations (EOP) Reliability Standards EOP-004-4 (Event Reporting), EOP-005-3 (System Restoration from Blackstart Resources), EOP-006-3 (System Restoration Coordination), and EOP-008-2 (Loss of Control Center Functionality).¹⁹¹ “The proposed standards substantially improve upon the existing standards by enhancing the requirements for Emergency operations, including the communication and coordination amongst reporting entities.”¹⁹² Specifically, proposed Reliability Standard EOP-004-4 requires the reporting of events by Responsible Entities, which are used to “examine the underlying causes of events, track subsequent corrective action to prevent recurrence of such events, and develop lessons learned for industry;” proposed Reliability Standard EOP-005-3 “(1) emphasizes the need for Transmission Operators to not only develop, but utilize restoration plans relating to Blackstart Resources; (2) streamlines the

185. *Id.* at 4.

186. Letter Order, Petition for Approval of Proposed Reliability Standards IRO-002-5 and TOP-001-4 at 2, FERC Docket No. RD17-4-000 (Apr. 17, 2017).

187. Joint Petition for Approval of Proposed Regional Reliability Standard VAR-501-WECC-3, *N. Am. Elec. Reliability Corp.*, No. RD17-5-000 (Mar. 10, 2017).

188. *Id.* at 3.

189. *Id.*

190. Letter Order, Joint Petition for Approval of Proposed Regional Reliability Standard VAR-501-WECC-3, FERC Docket No. RD17-5-000 (Apr. 28, 2017).

191. Petition for Approval of Proposed Emergency Operations Reliability Standards, FERC Docket No. RM17-12-000 (Mar. 27, 2017).

192. *Id.* at 3.

standard and retires redundant or administrative requirements; and (3) clarifies requirements for revising and testing restoration plans;” proposed Reliability Standard EOP-006-3 “(1) emphasizes the need for Reliability Coordinators to not only develop, but utilize their restoration plans; (2) streamlines the standard and retires redundant or administrative requirements; and (3) clarifies requirements around training and coordination of restoration plans amongst Reliability Coordinators;” proposed Reliability Standard EOP-008-2 clarifies “the required contents of an Operating Plan used by Reliability Coordinators, Balancing Authorities and Transmission Operators.”¹⁹³ On April 28, 2017, NERC submitted errata changes to the March 27, 2017, petition, replacing Exhibit C to correct an inadvertent exhibit error.¹⁹⁴

VI. OTHER FERC RELIABILITY INITIATIVES

A. Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans—Further Joint Study Report: Planning Restoration Absent SCADA or EMS (Jun. 2017)

In September 2014, FERC, NERC, and the eight Regional Entities initiated a study to assess the “restoration and recovery of the bulk-power system following a widespread outage or blackout.”¹⁹⁵ That report “culminated in the issuance of a joint [r]eport” that was published in January 2016.¹⁹⁶ This report gave “a comprehensive understanding of the electric utility industry’s bulk-power system recovery and restoration planning, [but] it [] identified certain issues that went beyond the scope of the [report], and recommended further study of those issues.”¹⁹⁷ One of these recommendations for further study was “the loss of Supervisory Control and Data Acquisition (SCADA) systems [during] system restoration” because system operators rely heavily on these “systems in performing and managing the restoration process.”¹⁹⁸

“The primary objective of this review [was] to identify areas” where an entity’s bulk-power restoration plan may prove “difficult in the absence of SCADA, [Inter-Control Center Communications Protocol] ICCP data, and/or [Energy Management System], and identify viable resources, methods or practices to enable timely system restoration in the absence of SCADA/EMS functionality, which could then be incorporated into entities’ system restoration training.”¹⁹⁹ “The joint study team found that” the participants in the study had made significant investments in their SCADA and EMS infrastructure to avoid a potential loss of these

193. *Id.* at 7, 23-24, 34, 38.

194. Errata to Petition for Approval of Proposed Emergency Operations Reliability Standards, FERC Docket No. RD17-12-000 (Apr. 28, 2017).

195. FED. ENERGY REGULATORY COMM’N & N. AM. ELEC. RELIABILITY CORP., REPORT ON THE FERC-NERC-REGIONAL ENTITY JOINT REVIEW OF RESTORATION AND RECOVERY PLANS—FURTHER JOINT STUDY REPORT: PLANNING RESTORATION ABSENT SCADA OR EMS 3 (2017) [hereinafter FERC & NERC Report].

196. *Id.*

197. *Id.*

198. *Id.*

199. FERC & NERC Report, *supra* note 195, at 7.

systems.²⁰⁰ Even with these investments and redundancies, the participants had prepared for the possibility that it would become partially or completely unavailable.²⁰¹ However, if this happened, it would be difficult and time-consuming to restore the bulk-power system because of the loss of these systems.²⁰² Thus, the joint study had these following recommendations or best practices: (1) to have a plan for backup communications measures and capability in case of the loss of normal communications during system restoration without the availability of SCADA or EMS; (2) to have a plan for personnel support when restoring the system without SCADA to ensure that the human resource operations can support the field and control room personnel; (3) ensuring that there are backup power supplies for extended time periods because of the increased time to accomplish system restoration without SCADA/EMS; (4) because the absence of SCADA/EMS functionality means the loss of State Estimator (SE) and Real-Time Contingency Analysis (RTCA) abilities, there need to be other ways of analyzing restoration information, especially during the later stages of restoration; and (5) ensure that the loss of SCADA/EMS scenarios are incorporated in system restoration training.²⁰³

B. Essential Reliability Services

Small Generator ride through (NOPR) – Updates

On July 21, 2016, FERC issued Order No. 828 revising the *pro forma* Small Generator Interconnection Agreement (SGIA) to require new interconnection customers to ensure the frequency ride through capability and the voltage ride through capability of small generating facilities.²⁰⁴ The FERC found 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.”²⁰⁵ The FERC “decline[d] to incorporate by reference any specific [technical] standard[s] into the *pro forma* SGIA.”²⁰⁶ On August 8, 2016, FERC issued a Notice of Extension of Compliance Dates extending the dates for compliance deadlines for Order No. 828 and Order No. 827 while “requir[ing] a single combined compliance filing” no later than October 14, 2016.²⁰⁷ The FERC previously issued Order No. 827 on June 16, 2016, revising the *pro forma* LGIA and *pro forma* SGIA and eliminating the exemption for wind generators.²⁰⁸

Frequency Response (NOI) – Updates

200. *Id.* at 11.

201. *Id.*

202. *Id.*

203. *Id.* at 17, 25, 29, 34, 38.

204. Order No. 828, *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 156 F.E.R.C. ¶ 61,062 (2016) (to be codified at 18 C.F.R. pt. 35).

205. *Id.* at p. 1.

206. *Id.* at P 33.

207. Notice of Extension of Compliance Dates, FERC Docket Nos. RM16-1-000, RM16-8-000 (Aug. 8, 2016).

208. Order No. 827, *Reactive Power Requirements for Non-Synchronous Generation*, 155 F.E.R.C. ¶ 61,277 (2016).

On November 17, 2016, FERC issued a NOPR proposing to revise the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* SGIA “to require all newly interconnecting . . . generating facilities . . . to install and enable primary frequency response capability as a condition of interconnection.”²⁰⁹ The FERC preliminarily found 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.”²¹⁰ The FERC also “preliminarily [found] that revisions to the *pro forma* LGIA and *pro forma* SGIA are appropriate.”²¹¹ The FERC asked for comments on its proposed:

(1) requirements for new large and small generating facilities to install, maintain, and operate a governor or equivalent controls; (2) requirements for [specific] droop and dead band settings . . . ; (3) requirements for timely and sustained response; (4) requirement for droop parameters to be based on nameplate capability with a linear operating range . . . ; (5) exemptions for new nuclear units; and (6) effective dates.²¹²

On January 24, 2017, NERC submitted comments to the FERC.²¹³ NERC stated that the FERC’s proposals “are consistent with the results of recent NERC reliability assessment recommendations.”²¹⁴ NERC also stated that it continues to study whether to impose frequency response requirements on existing resources.²¹⁵

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

A. ROP Filings

1. Appendix 2/Appendix 5A/Appendix 5B (Aug. 2016)

On August 15, 2016, NERC filed a petition with FERC in Docket No. RR16-5-000, seeking approval of targeted revisions to the following sections of the NERC Rules of Procedure: (i) “Appendix 2: Definitions Used in the Rules of Procedure;” (ii) “Appendix 5A: Organization Registration and Certification Manual;” and (iii) “Appendix 5B: Statement of Compliance Registry Criteria.”²¹⁶

209. Notice of Proposed Rulemaking, *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, 157 F.E.R.C. ¶ 61,122 at p.1 (2016).

210. *Id.* at P 24.

211. *Id.* at P 43.

212. *Id.* at P 56.

213. Comments of N. Am. Elec. Reliability Corp. in Response to Notice of Proposed Rulemaking, FERC Docket No. RM16-6-000 (Jan. 24, 2016).

214. *Id.* at 5.

215. *Id.* at 7-8.

216. Petition of N. Am. Elec. Reliability Corp. for Approval of Proposed Revisions to the Rules of Procedure 1, FERC Docket No. RR16-5-000 (Aug. 15, 2016).

NERC propose[d] revisions to incorporate Frequency Response Sharing Group and Regulation Reserve Sharing Group within the [Rules of Procedure], consistent with those terms as defined in the Glossary of Terms Used in NERC Reliability Standards [] and used in Reliability Standards BAL-003-1.1 and BAL-001-2, as approved in Order Nos. 794 and 810.²¹⁷

On November 4, 2016, the proposed revisions were accepted as filed via delegated letter order, effective October 31, 2016.²¹⁸

2. Section 400/Appendix 2/Appendix 4C (Dec. 2016)

On December 9, 2016, NERC filed a petition with FERC in Docket No. RR17-2-000 seeking approval of targeted revisions to the following sections of the NERC Rules of Procedure: (i) “Section 400: Compliance Enforcement;” (ii) “Appendix 2: Definitions Used in the Rules of Procedure;” and (iii) “Appendix 4C: Compliance Monitoring and Enforcement Program.”²¹⁹

The NERC Rules of Procedure “contemplate that hearings to resolve contested noncompliance, mitigation plans, remedial action directives, penalties, or sanctions may be conducted by each Regional Entity.”²²⁰ In its December 9, 2016 petition, “NERC propose[d] revisions to incorporate the Consolidated Hearing Process within the [Rules of Procedure], which would provide Regional Entities [with] an option to select NERC to manage the hearing process.”²²¹

The Commission has not yet acted on NERC’s petition.

3. Section 600/900 (June 2017)

On June 26, 2017, NERC filed a petition with the FERC in Docket No. RR17-6-000, seeking approval of targeted revisions to the following sections of the NERC Rules of Procedure: (i) Section 600: Personnel Certification, and (ii) Section 900: Training and Education.²²²

NERC proposed the revisions as part of its first comprehensive review to modernize and align the language of the Rules of Procedure with current Electric Reliability Organization (“ERO”) practices.²²³ According to NERC, the proposed revisions “delineate[] the responsibilities, governance and scope of the Personnel Certification Program, the Training and Education Program and the Continuing

217. *Id.* at 1-2.

218. Letter Order, NERC Proposal to Revise Appendix 2, Appendix 5A, and Appendix 5B of the NERC Rules of Procedure to Incorporate the Terms Frequency Response Sharing Group and Regulation Reserve Sharing Group, FERC Docket No. RR16-5-000 (Nov. 4, 2016).

219. Petition of N. Am. Elec. Reliability Corp. for Approval of Proposed Revisions to the Rules of Procedure 1, FERC Docket No. RR16-5-000 (Dec. 9, 2016).

220. *Id.*

221. *Id.*

222. Petition of the N. Am. Elec. Reliability Corp. for Approval of Proposed Revisions to the Rules of Procedure 1, FERC Docket No. RR17-6-000 (June 26, 2017).

223. *Id.* at 3.

Education Program.”²²⁴ NERC also stated that the proposed revisions “streamline[] the [Rules of Procedure] by eliminating detailed programmatic requirements duplicated in existing program manuals for the ERO.”²²⁵

The Commission has not yet acted on NERC’s petition.

224. *Id.*

225. *Id.*

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