REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant legal developments pertaining to the electric power system from July 1, 2022 through December 31, 2022.*

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I. THE DEFENSE PRODUCTION ACT AND THE DEPARTMENT OF ENERGY

On October 3, 2022, the United States Department of Energy (DOE) issued a request for information (RFI) seeking public input on how the DOE can leverage its authority under the Defense Production Act (DPA) to strengthen grid reliability and bolster national security.[1] The RFI came as result of the Biden Administration issuing presidential determinations that granted the DOE authority under the DPA to accelerate domestic production of five crucial energy technologies: (1) solar; (2) transformers and electric grid components; (3) heat pumps; (4) insulation; and (5) electrolyzers, fuel cells, and platinum group metals.[2]

Under the DPA, the DOE has various potential strategies to strengthen domestic supply chains, including purchases, purchase commitments, and financial assistances. The presidential determination explicitly states that a for a clean energy economy, including a "resilient energy sector" and preservation of critical infrastructure, is essential to national security.[3]

A. The Defense Production Act of 1950

Originating in the Cold War-era, the DPA of 1950 grants vast authority to the President to ensure that the nation's industry sector can adequately provide in the interest of national security.[4] The President is permitted to shape the nation's industrial base as part of the assurance that it is capable of producing and providing essential materials and goods, if and when it is called on to do so.[5] As such, the

1. *DOE Seeks Input on How Defense Production Act Could Support National Security by Strengthening Grid Reliability*, U.S. DEP'T OF ENERGY (Oct. 3, 2022), https://www.energy.gov/articles/doe-seeks-input-how-defense-production-act-could-support-national-security-strengthening.

2. *President Biden Invokes Defense Production Act to Accelerate Domestic Manufacturing of Clean Energy*, U.S. DEP'T OF ENERGY (June 6, 2022), https://www.energy.gov/articles/president-biden-invokes-defense-production-act-accelerate-domestic-manufacturing-clean.

3. Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Transformers and Electric Power Grid Components, 87 Fed. Reg. 35, 079 (2022).

4. 50 U.S.C. § 4511 (2014).

5. Jared T. Brown & Daniel H. Else, *The Defense Production Act of 1950: History, Authorities, and Reauthorization*, CONG. RSCH. SERV. (July 28, 2014), https://sgp.fas.org/crs/natsec/R43118.pdf.

DPA allows the President to shape national defense preparedness programs.[6] The DPA does include limits on the President's authority. The authority granted in the DPA must be exercised to promote, support, or otherwise be deemed needed or essential for national defense.[7] Currently, the DPA defines national defense as: " . . . programs for military and energy production or construction, military or critical infrastructure assistance to any foreign nation, homeland security, stockpiling, space, and any directly related activity. . . ."[8]

The DPA contains several provisions related to energy. Importantly, since 1980, "energy" has been designated as a *strategic and critical* material.[9] Further, the DPA emphasizes the importance of the inclusion of renewable energy and efficient energy storage and distribution technologies.[10]

Title I grants the President the authority to prioritize and allocate domestic energy materials, equipment, and services if "the President finds that such [domestic energy] materials, services, and facilities are scarce, critical, and essential (i) to maintain or expand exploration, production, refining, transportation; (ii) to conserve energy supplies; or (iii) to construct or maintain current energy facilities."[11] Additionally, the President must find that "maintenance or expansion of exploration, production, refining, transportation, or conservation of energy supplies or the construction and maintenance of energy facilities" cannot reasonably be accomplished without the exercise of the authority granted to the President in the DPA.[12]

Relatedly, Title III permits the President to expand the productive capacity and supply of *critical* materials and goods.[13] The purpose of Title III is to ensure the nation has adequate supplies of, or the ability to produce, essential materials and goods.[14] Under Title III, the President is permitted to provide economic incentives to encourage domestic industrial capabilities advancements.[15] Additionally, Title III establishes the Defense Production Act Fund (DPA Fund).[16] The DPA Fund is available to carry out Title III's provisions and purposes.

B. *Historic Usage of the DPA for Energy Security*

The DPA has been, and continues to be, a key element of federal law for ensuring energy security and provides a direct link between national defense and sufficient domestic energy supplies. Historically, Title I and Title III have been useful for such purposes.

6. Heidi M. Peters, *The Defense Production Act of 1950: History, Authorities, and Considerations for Congress*, CONG. RSCH. SERV. (Mar. 2, 2020), https://sgp.fas.org/crs/natsec/R43767.pdf.
7. *Id*.
8. 50 U.S.C. § 4552(14) (2009).
9. 50 U.S.C. § 4516 (2009) (emphasis added).
10. 50 U.S.C. § 4502(a)(5)-(6) (2009).
11. 50 U.S.C. § 4511(c)(2)(A)(i)-(iii) (2014).
12. 50 U.S.C. § 4511(c)(2)(B).
13. 50 U.S.C. § 4531(2010) (emphasis added).
14. *Id*.
15. *Id*.
16. Peters, *supra* note 6.

For example, under the Clinton administration, the DOE utilized Title I prioritization authorities to respond to the 2000-2001 California electricity crisis.[17] "The DOE utilized [its] authorit[y] to ensure that emergency supplies of natural gas continued to flow to California utilities."[18] In January 2001, President Clinton delegated authority under the DPA to the DOE.[19] Pursuant to that grant of authority, the DOE ordered out-of-state natural gas suppliers to sell natural gas to Pacific Gas & Electric to ensure continuity of gas service to California residents and businesses.[20] The DOE use of Title I authority was instrumental in the avoidance of threatened electrical blackouts.[21]

Following the 2000-2001 California electricity crisis, the 157th Congress instituted a Congressional Review of the DPA.[22] Acting General Counsel for the DOE, Eric J. Fygi, testified before the Senate Committee on Banking, Housing, and Urban Affairs.[23] Fygi testified that under the DPA presidential authority, "[i]n determining what the national defenses requires, it is clear the President may consider the potential impact of shortages of energy supplies."[24]

More recently, the Title III DPA Fund has been utilized for energy security purposes. In 2014-2016, Congress authorized the DOE to make "transfers of $45 million to the DPA Fund" from the Energy Efficiency and Renewable Energy account.[25] In its 2014 budget request, the "DOE stated [that] the $45 million would be used to support construction projects for commercial-scale biofuel production facilities . . . under a joint [Department of Defense]-Navy, DOE, and [United States Department of Agriculture] memorandum of agreement."[26] In total, "$135 million was transferred between FY2014-2016."[27]

17. *Review of the Defense Production Act in Relation to the California Energy Crisis Before the S. Comm. on Banking, Hous., and Urb. Affairs*, 107th Cong. (2001).

18. Michael Blackwell, *DOE Considers Using the Defense Production Act to Increase output and Deployment of Clean Energy Technology*, HUSCHBLACKWELL (Nov. 16, 2022), https://www.contractorsperspective.com/defense-production-act/doe-considers-using-the-defense-production-act-to-increase-output-and-deployment-of-clean-energy-technologies/.

19. Frank R. Lindh*, Keeping California's Pilot Lights Burning: A Rare Exercise of Presidential Powers*, 16 NAT. RES. & ENV'T 320, 320-21 (2001).

20. *Review of the Defense Production Act in Relation to the California Energy Crisis before the S. Comm. on Banking, Hous., and Urb. Affairs*, *supra* note 17. *See* Lindh, *supra* note 19, at 320-21.

21. *See generally Review of the Defense Production Act in Relation to the California Energy Crisis before the S. Comm. on Banking, Hous., and Urb. Affairs*, *supra* note 17.

22. *Id.*

23. *Id.*

24. *Id*. at 25 (statement of Eric J. Fygi, Acting Gen. Couns., Dep't of Energy).

25. Peters, *supra* note 6.

26. *Id.* at 13 n.79.

27. *Id*.

II. THE INFLATION REDUCTION ACT AND CLEAN ENERGY TAX INCENTIVES: THE PIVOTAL ROLE OF THE DEPARTMENT OF THE TREASURY AND INTERNAL REVENUE SERVICE

As part of the $369 billion dedicated to climate change, the Inflation Reduction Act of 2022 (IRA) provides $270 billion in tax incentives for climate change investment.[28] This significant investment puts the Department of the Treasury (Treasury) and the Internal Revenue Service (IRS) at the forefront of implementing the IRA.[29]

On October 5, 2022, to begin the implementation of the IRA, the Treasury and the IRS issued six Notices (October 5th Notices) requesting public guidance on implementation of key provisions.[30] The Notices sought input on specific questions, as well as general comments.[31] Specifically, the October 5th Notices requested comments on definitions, timing, qualifying technologies, and applications of certain provisions.[32] Additionally, input on guidelines and standards for verification purposes were requested. The October 5th Notices requested comment over six topics:[33] (1) Energy Generation Incentives;[34] (2) Credit Enhancements;[35] (3) Incentives for Homes and Buildings;[36] (4) Consumer Vehicle Credits;[37] (5) Manufacturing Credits;[38] and (6) Credit Monetization.[39]

First, Notice 2022-49 requested comments regarding provisions relating to production and investment tax credits in IRS Code section 45, section 45U, section 45Y, section 48, and section 48E.[40] Specifically, the Notice requested guidance for the new standalone energy storage credit[41] and standards for greenhouse gas emission reductions determinations.[42]

Second, Notice 2022-51 requested comments on the new Prevailing Wage, Apprenticeship, Domestic Content, and Energy Communities Requirements contained in provisions of IRS Code sections 30C, 45, 45L, 45Q, 45U, 45V, 45Y,

28. *Treasury Seeks Public Input on Implementing the Inflation Reduction Act's Clean Energy Tax Incentives*, U.S. DEP'T. OF THE TREASURY (Oct. 5, 2022), https://home.treasury.gov/news/press-releases/jy0993.

29. *Id.*

30. *Id.*

31. U.S. DEP'T. OF TREASURY, FACT SHEET: TREASURY, IRS OPEN PUBLIC COMMENT ON IMPLEMENTING THE INFLATION REDUCTION ACT'S CLEAN ENERGY TAX INCENTIVES 1 (2022), https://www.ferc.gov/sites/default/files/2020-05/comm-response.pdf.

32. *Id*. at 2.

33. *Id*.

34. *Id*.

35. FACT SHEET: TREASURY, IRS OPEN PUBLIC COMMENT ON IMPLEMENTING THE INFLATION REDUCTION ACT'S CLEAN ENERGY TAX INCENTIVE, *supra* note 31.

36. *Id.*

37. *Id.*

38. *Id.*

39. FACT SHEET: TREASURY, IRS OPEN PUBLIC COMMENT ON IMPLEMENTING THE INFLATION REDUCTION ACT'S CLEAN ENERGY TAX INCENTIVE, *supra* note 31.

40. Request for Comments on Certain Energy Generation Incentives, I.R.S. Notice 2022-49 (Oct. 5, 2022).

41. *Id.*

42. *Id.*

45Z, 48, 48C, 48E, and 179D.[43] If satisfied, these provisions will enable taxpayers to claim either an increased bonus credit or deduction.[44]

Third, Notice 2022-48 requested comments on incentive provisions for the improvement of energy efficiency residential and commercial buildings.[45]

Fourth, Notice 2022-46 requested comments on credits for clean vehicles under IRS Code sections 30D and 25E.[46] Section 30D contains a Clean Vehicle Credit, and the Notice requested comments relating to the critical minerals and battery components requirements that were included as part of the IRA.[47] Additionally, the IRA created a new Previously Owned Clean Vehicles Credit, which the Notice requested comments to guide implementation of the new credit.[48]

Fifth, Notice 2022-47 requested comments on Energy Security Tax Credits for Manufacturing under the new Advanced Manufacturing Production Credit under section 45X and the Qualifying Advanced Energy Project Credit under section 48C.[49] Specifically, guidance was requested on the "eligible components" definition for section 45X and selection criteria for section 48C.[50] However, the Notice did not request guidance on the prohibition of claiming both credits.[51]

Sixth, the IRA provides the option to monetize certain credits. The IRA does so in two ways: (1) direct payment election[52] and (2) transferability election.[53] Notice 2022-50 requested comments on the timing and manner of elections, in addition to certain entity-specific election issues.[54]

The Treasury and the IRS requested comments on the October 5th Notices to be submitted on or before November 5, 2022.[55]

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43. Request for Comments on Prevailing Wage, Apprenticeship, Domestic Content, and Energy Communities Requirements Under the Act Commonly Known as the Inflation Reduction Act of 2022, I.R.S. Notice 2022-51 (Oct. 5, 2022).

44. *Id.* Sections 30C, 45, 45Q, 45V, 45Y, 45Z, 48, 48C, and 48E contain provisions that permit increased credit amounts for qualifying taxpayers. *Id*. Section 179D includes an increased deduction amount for qualifying taxpayers. *Id.*

45. Request for Comments on Incentive Provisions for Improving the Energy Efficiency of Residential and Commercial Buildings, I.R.S. Notice 2022-48 (Oct. 5, 2022).

46. Request for Comments on Credits for Clean Vehicles, I.R.S. Notice 2022-46 (Oct. 5, 2022).

47. *Id.*

48. *Id.*

49. Request for Comments on Energy Security Tax Credits for Manufacturing Under Sections 48C and 45X, I.R.S. Notice 2022-47 (Oct. 5, 2022).

50. *Id*.

51. *Id*.

52. 26 U.S.C. § 6417 (2022).

53. 26 U.S.C. § 6418 (2022).

54. Request for Comments on Elective Payment of Applicable Credits and Transfer of Certain Credits, I.R.S. Notice 2022-50 (Dec. 12, 2022).

55. *IRS asks for comments on upcoming energy guidance*, IRS, https://www.irs.gov/newsroom/irs-asks-for-comments-on-upcoming-energy-guidance (last updated October 5, 2022).

III. EDF RENEWABLES, INC. V SOUTHWEST POWER POOL, 181 FERC ¶ 61,140

On November 17, 2022, FERC issued an Order granting in part and denying in part a complaint filed by a group of generator companies against Southwest Power Pool, Inc. (SPP) pursuant to sections 206, 306 and 309 of the Federal Power Act (FPA).[56] The complaint alleged that, in connection with implementation of the revenue crediting process in Attachment Z2 of SPP's Open Access Transmission Tariff (the "Tariff"),[57] "SPP has: (1) violated the terms of [its] Tariff and SPP Generators' project companies' Generator Interconnection Agreements (GIA), (2) engaged in unjust and unreasonable and unduly discriminatory and preferential practices, (3) violated the filed rate doctrine; and (iv) violated cost causation and beneficiary pays principles."[58] SPP Generators requested that the Commission grant their requested relief pursuant to FPA section 309.[59]

The Commission declined to dismiss the complaint on the grounds of collateral estoppel or *res judicata*.[60] Although the Commission previously had considered many of the same factual issues, this "SPP Generators' complaint raise[d] new questions [and issues] previously not considered by the Commission."[61]

The Commission found that SPP violated the Tariff and GIAs.[62] During the historical period, SPP was required to implement the process set forth in Attachment Z2, which provides that SPP must identify transmission customers taking service that could not have been provided but for Creditable Upgrades,[63] collect credit payment obligations from such transmission customers, and distribute revenue credits to upgrade sponsors.[64] There was no dispute that "SPP failed to implement this process as required by the Tariff during the historical period."[65] The Commission determined that "SPP could have sought a delay of the effective date of applicable Tariff provisions until it was able to invoice transmission service customers for Attachment Z2 credit payment obligations," but it did not do so.[66]

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56. *EDF Renewables, Inc.*, 181 FERC ¶ 61,140 (2022). The generator companies include EDF Renewables, Inc. (EDF renewables), EnelGreen Power North America, Inc. (Enel), NextEra Energy Resources, LLC (NextEra), and Southern Power Company (collectively, SPP Generators). *Id. See* 16 U.S.C. §§ 824e (1988), 825e (2005), 825h (1935).

57. SPP, Tariff, attachment Z2, § II. Under Attachment Z2, transmission customers, generation interconnection customers, and entities that request a Sponsored Upgrade are eligible to receive revenue credits for network upgrades whose costs have been directly assigned to them. SW. POWER POOL, OVERVIEW OF Z2 CREDITING PROCESS (2015), https://www.spp.org/documents/28841/overview%20of%20attachment%20z2%20crediting%20process_may%202015.pdf.

58. 181 FERC ¶ 61,140, at P 1.

59. *Id.*

60. *Id.* at P 74

61. *Id.*

62. 181 FERC ¶ 61,140, at P 76.

63. SPP, Tariff, attachment Z2, § II.

64. *Id*.

65. 181 FERC ¶ 61,140, at P 77.

66. *Id.*

"Instead, SPP later attempted to bill customers retroactively by seeking waiver of section 7.1 of the Tariff."[67]

Similarly, most of the GIAs state that "[I]nterconnection customer shall be entitled to [create] credits in accordance with Attachment Z2 of the Tariff for any network upgrades."[68] "The GIAs laid out the arrangements among the project companies, SPP, and other parties for how this compensation would be paid. However, SPP failed to implement Attachment Z2 during the historical period as required by the GIAs."[69]

The Commission also found "that SPP violated the filed rate doctrine as a result of the above-noted violations of the Tariff and the GIAs, which were the rates on file during the historical period."[70] "Under the filed rate doctrine, 'utilities are forbidden to charge any rate other than the one on file with the Commission'"[71] "[T]his violation arose[] [from] the Tariff violation."[72]

The Commission found that SPP did not engage in unjust, unreasonable and unduly discriminatory and preferential practices and did not violate cost causation and beneficiary pays principles.[73] The Commission acknowledged "even if SPP acted in good faith in the implementation and administration of Attachment Z2, the Tariff violation discussed above may result in an outcome that is unjust and unreasonable and/or unduly discriminatory and preferential."[74] The result may also "not [be] consistent with cost causation and beneficiary pays principle."[75] However, Commission held that the finding of a Tariff violation does not necessarily mean that SPP engaged in unjust, unreasonably and unduly discriminatory and preferential practices.[76]

The Commission denied SPP Generators' request to receive the full revenue credits and interest for transmission service SPP provided during the historical period using SPP Generators' Cunderedible Upgrades, since 2010, or alternatively to set the remedy phase of the complaint for settlement discussions before a Commission settlement judge.[77] Instead, the Commission concluded that SPP must refund the revenue credits, as the refund of revenue credits would not violate the

67. *Id.*

68. *Id.* at P 30; Letter from Southwest Power Pool to Kimberly D. Bose (Nov. 1, 2022) (Re: *Southwest Power Pool, Inc.,* Docket No. ER23-000, Submission of Tariff Revisions to Remove Barriers to Requesting Surplus Interconnection Service); *see* Letter from Penny S. Murrell to Tyler R. Brown (Oct. 16, 2012) (Re: *Generator Interconnection Agreement*, FERC Docket No. ER12-2507-000); Southwest Power Pool, *Open Access Transmission Tariff*, *Sixth Revised Vol. No. 1 – Attachment V Generator Interconnection Procedures*, Docket No. ER20-2955-000 at p. 195 (Dec. 1, 2020). SPP, Tariff, attachment V, app. 6 Generator Interconnection Agreement (16.0.0), art. 11.5.1.

69. 181 FERC ¶ 61,140, at P 78.

70. *Id*. at P 79.

71. *Id.* (citing W. Deptford Energy, LLC v. FERC, 766 F.3d 10, 12 (D.C. Cir. 2014)).

72. *Id.* at P 79.

73. 181 FERC ¶ 61,140, at P 81.

74. *Id.*

75. *Id.*

76. 181 FERC ¶ 61,140, at P 81.

77. *Id.* at P 82.

filed rate doctrine, but rather give effect to the rate on file.[78] Additionally, the Commission found that there were "no issues of material fact that could not be resolved on the basis of the written record."[79]

IV. EVERGY KANS. CENTRAL, INC., 181 FERC ¶ 61,044

On October 20, 2022, FERC issued an Order (October 20 Order) broadening sections 35.36(a)(9)(i) and (ii) of the Commission's regulations to include the appointment of independent directors.[80] The October 20 Order required Evergy Kansas Central, Inc., Evergy Missouri West, Inc. and Evergy Metro, Inc. (collectively, the "Evergy Sellers") to "submit additional information in order for the Commission to process the notice of change in status" of their upstream ownership within 30 days of the date of the order.[81] The October 20 Order found that (i) Elliott Management Corp. (Elliott) should not be deemed to be an affiliate of Evergy, Inc. (Evergy) and Evergy Sellers; and (ii) Bluescape Energy partners, LLC (Bluescape) was individually an affiliate of Evergy and Evergy Sellers under section 35.36(a)(9).[82]

Sections 35.36(a)(9)(i) and (ii) of the Commission's regulations define an "affiliate" as (i) "any person that directly or indirectly owns, controls, or holds with power to vote, 10% or more of the outstanding voting securities of the specified company" and (ii) "any company 10% or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company."[83] Additionally, section 35.36(a)(9)(iii) provides that an affiliate of a specified company may also be:

> [a]ny person or class of persons that the Commission determined, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate.[84]

Further, section 35.36(a)(9)(iv) specifies that "any person that is under common control with the specified company"[85] is an affiliate of the specified company. Lastly, section 35.36(a)(9)(v) specifies that "for purposes of paragraph (a)(9), owning, controlling or holding with power to vote, less than 10% of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control."[86]

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78. *Id.* at P 83.
79. *Id.* at P 87.
80. *Evergy Kansas Cent. Inc.*, 181 FERC ¶ 61,044.
81. *Id.* at P 1.
82. *Id.* at PP 43-44.
83. 18 C.F.R. § 35.36(a)(9)(i), (ii) (2021).
84. *Id*. § 35.36(a)(9)(iii).
85. *Id*. § 35.36(a)(9)(iv).
86. *Id*. § 35.36(a)(9)(v).

The Commission found that Elliott should not be deemed an affiliate of Evergy and Evergy Sellers.[87] Elliot owned less than 10% of the outstanding voting securities in Evergy, therefore, under section 35.36(a)(9)(v), it was entitled to a rebuttable presumption that it did not control Evergy.[88] There was evidence presented that Elliott negotiated to place members on the Evergy Board and that those members themselves had control over Evergy; however, these facts did not rebut the presumption of lack of control.[89]

As to whether there was a lack of arm's length bargaining between Elliott and Evergy under section 35.36(a)(9)(iii), the Commission found that record evidence was insufficient to require notice and comment procedures.[90] "[T]he director appointed to the Evergy Board at Elliott's request [was] independent of, and not compensated by, Elliott.[91] Therefore, it was concluded that Elliott was not an affiliate of Evergy and Evergy Sellers.[92]

The Commission found that Bluescape was individually an affiliate of Evergy and Evergy Sellers.[93] Although Bluescape's investments in Evergy were the same as Elliott's in many respects, the key difference was that Evergy had appointed one of Bluescape's own directors, its Executive Chairman, to the Evergy Board.[94] In a precedent case, the Commission had "expressed its 'concern with structures where the investor itself would be represented on the board through the appointment of the investor's own officers or directors, or other appointee accountable to the investor, in order to support a finding of control.'"[95]

The Commission was concerned about an appointment of a non-independent director from Bluescape to the Evergy Board and explained that

> [b]oard membership confers rights, privileges, and access to non-public information, including information on commercial strategy and operations. Where an investor's own officer or director, or other appointee accountable to the investor, is appointed to the board of a public utility or holding company that owns public utilities, the investor itself will have those rights, privileges, and access, and thus the authority to influence significant decisions involving the public utility or public utility holding company.[96]

The Commission concluded that where an investor's non-independent director is appointed to the board of a public utility or public utility holding company, that appointment rebuts the presumption of lack of control under section

87. 181 FERC ¶ 61,044, at P 43.
88. *Id.*
89. *Id.* at P 45.
90. *Id.* at P 43.
91. 181 FERC ¶ 61,044, at P 43.
92. *Id.* at 45.
93. *Id.* at P 44.
94. *Id.*
95. 181 FERC ¶ 61,044 (citing *Public Citizen, Inc. v. CenterPoint Energy, Inc.*, 174 FERC ¶ 61,101 at P 33 (2021)).
96. *Id.* at P 45.

35.36(a)(9)(v).[97] Therefore, Bluescape was deemed to be an affiliate of Evergy and Evergy Sellers.[98]

The Commission also declined to find that Elliott was affiliated with Evergy or Evergy Sellers by virtue of any joint activities with Bluescape.[99] There was not sufficient evidence to show that Elliott and Bluescape were acting in concert.[100]

V. INCENTIVES FOR ADVANCED CYBERSECURITY INVESTMENT, 180 FERC ¶ 61,189

On September 22, 2022, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking[101] proposing to establish incentives for utilities' advanced cybersecurity investment as directed by section 219A of the FPA as amended by section 40123 of the Infrastructure Investment and Jobs Act of 2021.[102] FERC proposed a regulatory framework establishing "how a utility could qualify for cybersecurity incentives."[103] FERC also proposed rate incentives that would be available to a utility with qualifying cybersecurity expenditures.[104] FERC further proposed incentive implementation issues, including incentive duration, expiration, filing, and reporting requirements.[105]

A. Section 219A of the Federal Power Act Directives to FERC

Section 219A(b) of the FPA directed FERC, in consultation with the Secretary of Energy, the North American Electric Reliability Corporation, the Electricity Subsector Coordinating Council, and the National Association of Regulatory Utility Commissioners, to identify incentive-based rate treatments that FERC could use to encourage investment in advanced cybersecurity and participation in cybersecurity threat information sharing programs.[106] FERC submitted the non-public report to Congress on May 13, 2022.[107]

Section 219A(c) of the FPA directed FERC to

> revise its regulations to establish, by rule, incentive-based, including performance-based, rate treatments for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by public utilities

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97. *Id.*

98. *Id.* at P 44.

99. 181 FERC ¶ 61,044, at PP 43-44.

100. *Id.* at P 46.

101. Notice of Proposed Rulemaking, *Incentives for Advanced Cybersecurity Investments*, 87 Fed. Reg. 60,567 (2022).

102. *Id.* FERC expanded upon the statutory language directing FERC to offer incentives to "public utilities" in section 219A of the FPA by expanding the eligible list of utilities "to include both public utilities as well as non-public utilities that have or will have a rate on file with the Commission." *Id.* at 60,568 n.3. *See* Infrastructure Investment and Jobs Act of 2021, Pub. L. 117-58, section 40123, 135 Stat. 429, 951 (to be codified at 16 U.S.C. 824s-1)

103. 87 Fed. Reg. 60,567, at 60,568.

104. *Id.* at 60,569.

105. *Id.*

106. Infrastructure Investment and Jobs Act of 2021 § 135 at 952 (to be codified at 16 U.S.C. 824s-1(b)).

107. 87 Fed. Reg. 60,567, at 60,569.

> for the purpose of benefitting consumers by encouraging investments by public utilities in advanced cybersecurity technology and participation by public utilities in cybersecurity threat information sharing programs.[108]

Section 219A of the FPA directed FERC to consider additional factors including: (1) small and medium-sized public utilities with limited cybersecurity resources[109] and (2) ratepayer protections.[110] In addition, section 219A of the FPA permits utilities to submit single-issue rate filings with FERC when requesting advanced cybersecurity incentives.[111]

B. Proposed Approaches to Request an Incentive

1. Eligibility Criteria

FERC proposed that utilities seeking incentives must demonstrate that the expenditure meets two eligibility criteria: (1) it "would materially improve cybersecurity through either an investment in advanced cybersecurity technology or participation in a cybersecurity threat information sharing program(s);" and (2) "it would constitute investment in advanced cybersecurity technology or participation in a cybersecurity threat information sharing program(s)."[112] FERC proposed that it would consider six federal resources to determine which cybersecurity expenditures would materially improve a utility's security posture.[113]

2. Proposed Approaches for Cybersecurity Expenditure Eligibility Evaluation

FERC proposed that utilities would need to make a filing with FERC pursuant to section 205 of the FPA to request an advanced cybersecurity incentive and that the incentive would not be effective before the FERC order approving the incentive.[114] FERC also proposed creating a prequalified list (PQ List) of expenditures that could receive an incentive.[115] FERC further proposed that a filing would be entitled to a rebuttable presumption of eligibility for an item on the PQ List.[116] FERC proposed an initial PQ List that includes expenditures associated with participation in the Department of Energy's Cybersecurity Risk Sharing Program (CRISP)[117] and expenditures associated with internal network security monitoring within the utility's cyber systems.[118]

108. *Id.*; *see also* Infrastructure Investment and Jobs Act of 2021, § 135 at 952.
109. Infrastructure Investment and Jobs Act of 2021, § 135 at 952.
110. *Id.* at 952-53.
111. *Id.* at 953.
112. 87 Fed. Reg. 60,567, at 60,570, 60,572.
113. *Id.* at 60,571.
114. *Id.*
115. *Id.*
116. 87 Fed. Reg. 60,567, at 60,571.
117. *Id.*
118. *Id.* at 60,572.

FERC also sought comment on whether and how the Commission could implement a case-by-case approach to utilities requesting advanced cybersecurity incentives.[119] FERC noted that case-by-case filings would not receive the rebuttable presumption of eligibility but would instead be held to the standard for all filings pursuant to section 205 of the FPA.[120]

C. *Proposed Rate Incentives*

FERC proposed that a utility could seek two rate incentives for eligible cybersecurity investments, a return on equity (ROE) adder or a deferral of cybersecurity expenses for rate recovery.[121] FERC noted that the same expenditure could only qualify for one of the proposed incentives.[122]

1. ROE Adder

FERC proposed to apply a 200 basis point ROE adder on cybersecurity investments eligible for incentives and not on the utility's entire rate base.[123] FERC stated that rates that include cybersecurity ROE incentives would still be subject to the total base and "incentive return being capped at the top of the utility's zone of reasonableness."[124] FERC justified the large ROE adder by stating that the costs of cybersecurity investments were small when compared to conventional transmission projects.[125]

2. Deferral of Certain Cybersecurity Expenses for Rate Recovery

FERC proposed to allow a utility to defer recovery of certain cybersecurity costs and treat those expenses as capital investments included in the utility's rate base.[126] FERC noted that, with this incentive, a cybersecurity service with periodic payments would be treated as an asset for ratemaking purposes, and the utility would be able to capitalize and earn an ROE on the cost of the cybersecurity service.[127] FERC sought comment on whether the regulatory asset incentive should apply to the entire cost or instead to 50% of the cost.[128] FERC provided several examples of cybersecurity costs that could be eligible for a regulatory asset incentive including training, subscription, service agreement costs, and payments made to participate in cybersecurity threat information sharing programs.[129]

119. *Id*.
120. 87 Fed. Reg. 60,567, at 60,572.
121. *Id.*
122. *Id.* at 60,573.
123. *Id.*
124. 87 Fed. Reg. 60,567, at 60,573.
125. *Id.*
126. *Id.*
127. *Id.*
128. 87 Fed. Reg. 60,567, at 60,573.
129. *Id.*

3. Performance-Based Rates

FERC sought comment on whether performance-based rates would be appropriate and what metrics could be used to measure performance.[130]

D. Proposed Incentive Implementation

1. Incentive Duration

FERC proposed that a cybersecurity ROE incentive would last until the earliest of:

> (1) the conclusion of the depreciation life of the underlying asset; (2) five years from when the cybersecurity investment(s) enter service; (3) the time that the investment(s) or activities that serve as the basis of that incentive become mandatory pursuant to a Reliability Standard approved by FERC, or local, state, or Federal law; or (4) the recipient no longer meets the requirements for receiving the incentive.[131]

FERC proposed "that a utility granted the Regulatory Asset Incentive must amortize the regulatory asset over five years."[132] FERC also proposed to permit a utility to "defer eligible expenses for up to 5 years" from the date of FERC approval.[133] FERC proposed an exception for this sunsetting would be for participation in an eligible cybersecurity threat information sharing programs for as long as the utility continues incurring costs for its participation in the program and the program remains eligible for incentives.[134]

2. Filing Process

FERC proposed that utilities would need to make a filing pursuant to section 205 of the FPA and FERC would need to approve that filing before a utility could receive an incentive.[135] FERC further proposed that utilities would need to show how the cybersecurity expenditures would meet the eligibility requirements.[136]

3. Reporting Requirements

FERC proposed to require utilities that receive a cybersecurity incentive to make an annual informational filing with the Commission by June 1 that details the specific investments, if any, as of that date, that were made pursuant to the Commission's approval and the corresponding FERC account for which expenditures are booked.[137] FERC proposed that annual filings by recipients of the cybersecurity ROE incentive should describe the parts of its network that it upgraded in addition to the nature and cost of the various investments.[138] FERC proposed that

130. *Id*. at 60,574.
131. *Id*.
132. 87 Fed. Reg. 60,567, at 60,574.
133. *Id.*
134. *Id*.
135. *Id*. at 60,575.
136. 87 Fed. Reg. 60,567, at 60,575.
137. *Id*.
138. *Id.*

annual filings by recipients of the regulatory asset incentive "should describe such expenses in sufficient detail to demonstrate that such expenses are specifically related to the eligible cybersecurity investment underlying the incentives and not for ongoing services including system maintenance, surveillance, and other labor costs."[139]

E. Deadlines

Public comments were due to FERC on November 7, 2022, and reply comments were due to FERC on November 21, 2022. Section 219A(c) of the FPA requires FERC to issue a Final Rule establishing cybersecurity incentives no later than May 12, 2023.[140]

VI. FERC ORDER ON SPP "BYWAY" FACILITY COST ALLOCATION, 181 FERC ¶ 61,076

On October 28, 2022, FERC issued an order accepting tariff revisions filed by the Southwest Power Pool (SPP) "to establish a process through which, on a case-by-case basis," the full costs of certain "Byway" transmission facilities—facilities "with a voltage level between 100kV and 300 kV can be allocated" to ratepayers across the entire SPP region.[141] The Commission concluded that because certain Byway facilities may provide significant benefits to zones across the SPP region, the costs of these facilities may be allocated across the region on a postage-stamp basis, in accordance with the cost causation principle.[142] Commissioners Danly and Christie dissented, each explaining that he finds the proposal unjust and unreasonable without record evidence of support from a supermajority of public utility commissions from SPP states.[143]

A. Background

Since 2010, SPP has used a "Highway/ Byway" cost allocation methodology that allocates the costs of new "transmission facilities on a voltage threshold basis."[144] Under this methodology, SPP allocates the costs of all new transmission facilities of 300 kV or higher (Highway Facilities) on a regional basis, using a postage-stamp method of cost allocation.[145] The costs of Byway facilities, meanwhile, were split; SPP allocated 33% of the costs of any Byway facility "on a

139. *Id.*

140. Infrastructure Investment and Jobs Act of 2021, § 135 at 952.

141. *Sw. Power Pool, Inc.*, 181 FERC ¶ 61,076 (2022).

142. *Id*. at P 48 (citing S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 87 (D.C. Cir. 2014) (explaining that the cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits).

143. *Id.* (Danly, Christie, Comm'rs, dissenting).

144. *Id.* at P 2 (citing *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010), *reh'g denied*, 137 FERC ¶ 61,075 (2011)).

145. 181 FERC ¶ 61,076, at P 2.

regional, postage-stamp basis and 67% of the costs to the SPP pricing zone in which the facilit[y] [is] located."[146]

In 2021, SPP filed a proposal with the Commission to establish a review process through which builders of Byway transmission facilities could petition the SPP Board of Directors (SPP Board) for permission to treat certain Byway facilities, on a case-by-case basis, like Highway facilities for cost allocation purposes.[147] In its order rejecting SPP's 2021 filing, the Commission held that the filed proposal "would grant the SPP Board too much discretion in allocating the costs of Byway facilities without clear standards for how its cost allocation decisions would be made."[148] The Commission also held in the Rejection Order that the proposed Tariff language lacked transparency, including into the standards, criteria, or thresholds that would be used to review petitions for Highway treatment of Byway facilities.[149]

On May 10, 2022, SPP filed a revised proposal to establish a process through which Byway facility sponsors can seek regional cost allocation.[150] In support of its proposal, SPP argued that allocating the costs of new transmission infrastructure built in wind-abundant zones primarily to the local zone resulted in a misalignment between the costs of those transmission assets and the benefits received from them.[151] The revised proposal also defined the criteria that the SPP Board, in cooperation with certain stakeholder committees, would use to evaluate applicants' projects.[152]

B. Determination

In accepting SPP's revised Byway cost-allocation proposal, the Commission held that the proposed methodology "will help ensure that the costs of Byway facilities are allocated in a manner that is at least roughly commensurate with benefits."[153] The Commission also approved SPP's proposal to use certain objective criteria to measure the physical and economic benefits that new Byway facilities provide to the entire SPP region.[154] The Commission explained that the three criteria that SPP proposed to measure benefits—the Capacity Criterion, the Flow Criterion, and the Benefit Criterion—together serve both to identify SPP zones with high energy exports and to quantify the system-wide benefits delivered by any new project seeking cost recovery.[155]

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146. *Id*.
147. *Id*. at P 4.
148. *Id.* at P 4 (citing *Sw. Power Pool, Inc.*, 175 FERC ¶ 61,198, at PP 38-39 (2021) (Rejection Order)).
149. 181 FERC ¶ 61,076, at P 4.
150. *Id*. at P 5.
151. *Id*. at P 7.
152. *Id.* at P 9.
153. 181 FERC ¶ 61,076, at P 48.
154. *Id.*
155. *Id*. at PP 48, 50.

C. Dissents

Commissioner James Danly dissented from the Byway Order, arguing that it grants too much discretion to the SPP Board and noting that state public utility commissions were not united in their support of the proposal.[156] Commissioner Mark Christie also dissented, arguing that the underlying conditions that prompted the 2010 Highway/ Byway cost allocation remain largely the same and, therefore, that any fundamental change to SPP's cost allocation methodology that would shift costs from one state to another should represent a "strong consensus" among the SPP states.[157]

D. Moving Forward

The Byway Order is one of several reforms to transmission planning and cost allocation that have been proposed recently by SPP, as the wind-rich region seeks to respond to the many interconnection requests and associated transmission system upgrades needed to accommodate new generation.[158] On September 30, 2022, for example, SPP submitted proposed tariff revisions to facilitate the self-funding of network upgrades and system protection facilities by transmission owners.[159] On November 30, 2022, FERC staff issued a deficiency letter requesting more information on the proposal.[160] SPP has until January 29, 2023 to file a response.[161] Separately, SPP's Cost Allocation Working Group (CAWG) of stakeholders continues to discuss cost-sharing principles for projects identified as part of the MISO-SPP Joint Targeted Interconnection Queue Study (JTIQ).[162] Together, these and other efforts are intended to move SPP forward in facilitating the interconnection of all economic generation and allocating the costs of any necessary transmission upgrades fairly among SPP customers.

VII. FERC ORDER AUTHORIZING DISPOSITION OF JURISDICTIONAL FACILITIES AND ACQUISITION OF SECURITIES, 181 FERC ¶ 61,055

On October 20, 2022, the Federal Energy Regulatory Commission (FERC) issued its order pursuant to a request by TransAlta Energy Marketing (U.S.) Inc.

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156. *Id.* at PP 2, 6 (Danly, Comm'r, dissenting).

157. 181 FERC ¶ 61,076, at PP 2-4 (Christie, Comm'r, dissenting).

158. Tom Kleckner, *FERC Approves SPP Cost-Allocation Waiver Plan*, RTO INSIDER (Nov. 7, 2022), https://www.rtoinsider.com/articles/31086-ferc-approves-spp-cost-allocation-waiver-plan.

159. Letter from Southwest Power Pool to Kimberly D. Bose (Sept. 30, 2022) (Re: *Southwest Power Pool, Inc.,* Docket No. ER22-000, Submission of Tariff Revisions to Add Provisions for Self-Funding Network Upgrades and System Protection Facilities),

160. Letter from Penny S. Murrell to Britney Lloyd (Nov. 30, 2022) (Re; Tariff Revisions for Self-Fund of Network Upgrades and System Protection Facitilites, FERC Docket No. ER22-2968-000).

161. *Id.*

162. SOUTHWEST POWER POOL COST ALLOCATION WORKING GROUP, SUMMARY OF MOTIONS AND ACTION ITEMS 3 (2022), https://spp.org/documents/68254/cawg%20november%208,%202022%20minutes.pdf.

et.al[163] for approval for a change in control that would take place upon the expiration of its Standstill Agreement (Agreement) effective with their 2019 debt securities agreement between TransAlta Corporation (TransAlta) and Brookfield BRP Holdings (Canada) Inc. (ultimately owned by Brookfield Asset Management, Inc. or BAM) an investor in the proposed transaction.[164] TransAlta filed the approval request pursuant to sections 203(a)(1)(A) and (a)(2) of the FPA on February 28, 2022.[165]

The request sought to obtain FERC authorization for Eagle Canada Common Holdings LP and BIF IV Eagle NR Carry LP, (collectively as "Investors") both wholly-owned indirect subsidiaries of BAM to own greater than 10% of the voting Common Shares of TransAlta.[166] The filing requests approval for the change of control upon expiration of the Agreement on or about May 1, 2022.[167] In its filing, TransAlta argues that although Investors owned over 10% of voting Common Shares of TransAlta (approximately 13% at filing), that due to the several prohibitions of Investor activities contained in the Agreement, Investors would have no ability to exercise control of TransAlta and its affiliated entities.[168] TransAlta did not seek prior approval from FERC upon Investors' purchase of greater than 10% of TransAlta Common Shares in aggregate; and TransAlta and Investor have an agreement in place to appoint up to "two out of 12 members" to TransAlta's Board of Directors and at time of filing had placed two on the TransAlta Board of Directors.[169]

In its application, TransAlta cited *Cascade Investment, LLC*[170] for its support that given the restrictions in its Standstill Agreement, it believed no prior request for change in control was required while Agreement was in force.[171] The *Cascade* proceeding involved a Standstill Agreement with several restrictions as to actions purchaser *Cascade* could take with regard to control of a public utility's holding company Otter Tail Corporation (Otter Tail).[172] These restrictions included: 1) a limit on Cascade holdings to "less than 20% of" outstanding Otter Tail voting securities; 2) commitment by *Ca*scade to not hold any seats on Otter Tail's Board of Directors nor to seek to influence the price of power sold from Otter Tail generation units; and 3) other restrictions preventing any ability for Cascade to influence Otter Tail interests through voting securities.[173] The Commission found in the

163. *TransAlta Energy Mktg. (U.S.), Inc.,* 181 FERC ¶ 61,055 (2022) (other filing parties are: TransAlta Energy Marketing (U.S.) Inc.; TransAlta Energy Marketing Corp.; TransAlta Centralia Generation LLC; TransAlta Wyoming Wind LLC; Big Level Wind LLC; Eagle Canada Common Holdings LP; and BIF IV Eagle NR Carry LP).

164. *Id.* at P 1.

165. *Id.*

166. *Id.* at P 20.

167. 181 FERC ¶ 61,055, at P 23.

168. *Id.* at P 20.

169. *Id.* at P 28.

170. *Id.* at P 26.

171. 181 FERC ¶ 61,055, at P 26.

172. *Id.*

173. *Id.*

Cascade proceeding that because of restrictions in the Agreement, that the proposed transaction would not result in any ability for Cascade to exercise control over Otter Tail.[174]

The Commission stated that it reviewed the TransAlta Application filed pursuant to its Merger Policy Statement.[175] The Commission upon its review found three essential distinctions between the *Cascade* acquisition and the TransAlta transaction: 1) the *Cascade* application was filed prior to it obtaining more than 10% of voting securities of Otter Tail (TransAlta obtained 10.1% share of Voting Securities in March 2020) therefore exceeding the ownership threshold for blanket authorization; 2) unlike Cascade, TransAlta had placed two members to the Otter Tail Board prior to the filing for approval of control; and 3) unlike the Cascade agreement, the TransAlta agreement contains no clearly defined limitations on its ability to vote its shares.[176] Due to these distinctions, the Commission found that citation of the *Cascade* transaction was not sufficient to prevent a change of control in the proposed transaction.[177] It further found that even in the case where no control was established, prior authorization would still have been required pursuant to section 203(a)(2) of the FPA since that section requires prior Commission approval for any purchase by a holding company of greater than $10 million in shares of a utility.[178] For these reasons, the Commission found that Applicants violated the requirements of FPA 203 by not filing a timely request for change in control prior to their acquisition of greater than 10% of the outstanding TransAlta shares in March of 2020.[179]

In its support of this finding, the Commission reiterated that it had previously found concerns with "structures where the investor itself would be represented by the board through the appointment of the investor's own officers or directors, or other appointee accountable to the investor, in order to support a finding of control."[180] It further stated that consistent with its recent decision in the *Evergy* proceeding[181] that "where an investor's own officer or director, or other appointee accountable to the investor, is appointed to the board of a public utility of holding company that owns public utilities, the investor itself will have those rights, privileges, and access, and thus the authority to influence significant decisions involving the public utility of public utility holding company."[182] The Commission therefore confirmed that the placement by the affiliate of two members to the TransAlta Board does create an independence conflict and does constitute a change in control.[183]

174. *Id.*
175. 181 FERC ¶ 61,055, at P 2 (2022).
176. *Id.* at PP 27-29.
177. *Id.* at P 31.
178. 181 FERC ¶ 61,055, at P 32.
179. *Id*. at P 33.
180. *Pub. Citizen, Inc.,* 174 FERC ¶ 61,101 at P 33 (2021).
181. *Evergy Kan. Centr., Inc*., 181 FERC ¶ 61,044 (2022).
182. 181 FERC ¶ 61,055, at P 29.
183. *Id.*

The Commission further evaluated the prospective transaction pursuant to FPA section 203(a)(4) as to whether it would be consistent with public interest.[184] This analysis centered on three factors: "(1) effect on competition [(vertical and horizontal market power)]; (2) effect on rates; and (3) effect on regulation."[185] In addition, "[s]ection 203(a)(4) also requires the Commission to find the proposed transaction 'will not result in any cross-subsidization'" between utility and non-utility interests nor encumber or pledge utility assets for the benefit of the non-utility interest – unless it finds the cross subsidization or encumbrance to be in the public interest.[186] The Commission reviewed the proposed transaction across these factors and found that it does not result in any violation of section 203(a)(4) of the FPA - nor result in any cross-subsidization between utility and non-utility interests.[187] The Commission approved the proposed transaction prospectively.[188]

VIII. REGISTRATION OF INVERTER-BASED RESOURCES, 181 FERC ¶ 61,124

On November 17, 2022, FERC issued an order directing the North American Electric Reliability Corporation (NERC), acting in its role as the FERC-approved Electric Reliability Organization (ERO), to submit a work plan to FERC within 90 days (*i.e.*, before February 15, 2023) that would describe NERC's plan to identify and register owners and operators of inverter-based resources (IBRs) connected to the Bulk-Power System that have a material aggregate impact on the reliable operation of the Bulk-Power System.[189]

FERC observed that as IBRs are deployed in greater numbers, their operations can have a material impact on the reliable operation of the Bulk-Power System.[190] FERC noted that while IBRs such as solar photovoltaic (PV), wind, fuel cells, and battery storage produce real and reactive power like synchronous generators, IBRs react to transmission system disturbances differently than the synchronous generators.[191] These differences are due to IBR operational characteristics and equipment settings and have in some instances exacerbated disturbances on the Bulk-Power System.[192]

FERC was concerned that while many IBRs fall below the threshold for inclusion in the bulk electric system definition they could, in the aggregate, have a material impact on the reliable operation of the Bulk-Power System.[193] FERC discussed twelve events included in seven NERC reports issued between 2016 and 2022 during which an average of approximately 1,000 MW of IBRs "act[ed] unexpectedly and adversely in response to normally cleared transmission line faults

184. 16 U.S.C. §824(a)(4) (2018).
185. 181 FERC ¶ 61,055, at P 34.
186. *Id.*
187. *Id*. at PP 44, 46.
188. *Id*. at P 2.
189. *Registration of Inverter-Based Resources*, 181 FERC ¶ 61,124 at P 1 (2022).
190. *Id*. at P 22.
191. *Id.*
192. *Id.*
193. 181 FERC ¶ 61,124, at P 23.

on the Bulk-Power System."[194] FERC also described the actions that NERC has undertaken since the initial IBR disturbance event in 2016 even though NERC's "actions to date have not successfully addressed the most common reliability issues posed by IBRs."[195]

FERC found that NERC should take action necessary to "register the owners and operators of those unregistered IBRs that, in the aggregate, have a material impact on Bulk-Power System reliability, to ensure those entities are subject to a relevant set of mandatory and enforceable Reliability Standard requirements."[196] FERC stated its concern that unregistered IBRs, in the aggregate, could have a material impact on the reliable operation of the Bulk-Power System.[197] To address this concern, FERC found that "unregistered IBRs connected to the Bulk-Power System, regardless of size and transmission or sub-transmission voltage, that in the aggregate have a material impact on Bulk-Power System performance should be registered" with NERC.[198]

FERC directed NERC to develop a work plan and submit it to FERC within 90 days for FERC approval.[199] FERC directed that the NERC work plan should explain how NERC will "identify and register unregistered IBRs that, in the aggregate, have a material impact on the reliable operation of the Bulk-Power System, but that are not currently required to be registered with NERC."[200] FERC declared that NERC's work plan will be noticed for public comment.[201] FERC required NERC's work plan to state how NERC will modify its processes to register IBRs within 12 months of FERC approval.[202] FERC also required NERC to identify the owners and operators of IBRs that would be required to register within 24 months of FERC approval and that they would be "registered and required to comply with applicable Reliability Standards within 36 months of" FERC approval.[203] FERC further directed NERC to file progress updates on the status of its work plan every 90 days following FERC approval of the work plan.[204] FERC issued this order concurrently with a notice of proposed rulemaking that proposed to require NERC to modify the Reliability Standards to address specific reliability gaps related to IBRs.[205]

FERC Commissioner Danly concurred with the order, noting his concerns that NERC may not be able to respond to reliability challenges quickly enough.[206]

194. *Id.* at P 24 n.59.
195. *Id.* at P 28.
196. *Id.* at P 31.
197. 181 FERC ¶ 61,124, at P 32.
198. *Id.*
199. *Id.* at P 33.
200. *Id.*
201. 181 FERC ¶ 61,124, at P 35.
202. *Id.*
203. *Id.*
204. *Id.*
205. Notice of Proposed Rulemaking, *Reliability Standards to Address Inverter-Based Resources*, 87 Fed. Reg. 74,541 (2022).
206. 181 FERC ¶ 61,124 (Danly, Comm'r, concurring).

IX. RELIABILITY STANDARDS TO ADDRESS INVERTER-BASED RESOURCES, NOTICE OF PROPOSED RULEMAKING, 181 FERC ¶ 61,125

A. Introduction and Background

On November 17, 2022, FERC issued a draft notice of proposed rulemaking (NOPR) proposing to direct the North American Electric Reliability Corporation (NERC) "to develop new or modified Reliability Standards addressing four reliability gaps pertaining to [inverter-based resources (IBRs)]: (1) data sharing; (2) model validation; (3) planning and operational studies; and (4) performance requirements."[207] FERC issued this NOPR concurrently with an order directing NERC to create a work plan addressing unregistered IBRs that have a significant impact on the Bulk-Power System.[208]

NERC is the FERC-certified Electric Reliability Organization (ERO).[209] Section 215(d)(5) of the FPA grants FERC the authority "upon its own motion or upon complaint," to order the ERO "to submit to the Commission a proposed Reliability Standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out" section 215 of the FPA.[210]

FERC identified three broad categories of IBRs: NERC-registered IBRs (registered IBRs), IBRs that are connected directly to the Bulk-Power System but are not registered with NERC (unregistered IBRs), and distributed energy resource (DER) IBRs that connect to distribution systems (IBR-DERs).[211]

FERC noted that while IBRs such as solar photovoltaic (PV), wind, fuel cells, and battery storage produce real and reactive power like synchronous generators, IBRs react to transmission system disturbances differently than the synchronous generators.[212] These differences are due to IBR operational characteristics and equipment settings and have in some instances exacerbated disturbances on the Bulk-Power System.[213] Two IBR modes of operation that pose a challenge to the reliable operation of the Bulk-Power System are tripping offline and momentary cessation.[214] FERC defines tripping offline as a mode of operation where the IBR

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207. 87 Fed. Reg. 74,541, at 74,542.

208. 181 FERC ¶ 61,124.

209. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom.* Alcoa, Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009).

210. 16 U.S.C. § 824o(d)(5) (2005); 18 C.F.R. § 39.5(f).

211. 87 Fed. Reg. 74,541, at 74,543 n.15 (citing *Revisions to Electric Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.*, 141 FERC ¶ 61,236 (2012) *order on reh'g*, 143 FERC ¶ 61,053 (2013) *rev'd sub nom.* People of the State of N.Y. v. FERC, 783 F.3d 946 (2d Cir. 2015); NERC, GLOSSARY OF TERMS USED IN NERC RELIABILITY STANDARDS 5-7 (Mar. 29, 2022), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

212. 87 Fed. Reg. 74,541, at 74,542.

213. *Id.*

214. *Id.*

"disconnects from the Bulk-Power System and/or distribution system and therefore cannot supply real and reactive power."[215] FERC defines momentary cessation as a mode of operation where "the inverter remains electrically connected to the Bulk-Power System, but the inverter does not inject current during low or high voltage conditions outside the continuous operating range," and as "a result, there is no current injection from the inverter and therefore no active or reactive current (and no active or reactive power)."[216]

B. *Need for Reform*

FERC stated that the current mandatory and enforceable Reliability Standards "were developed to apply to the generation resources prevalent at the time the standards were developed and adopted – nearly exclusively synchronous generation resources."[217] FERC also stated that the Reliability Standards do not sufficiently "account for the material technological differences between the response of synchronous generation resources and that of IBRs to the same disturbances on the Bulk-Power System."[218]

FERC further stated that recent events have "demonstrated the challenges to transmission planning and operations of the Bulk-Power System posed by gaps in the Reliability Standards specific to IBRs" in the areas addressed by the NOPR."[219] NERC has developed a voluminous record and taken various actions in to attempt to address the reliability concerns raised by increasing IBR deployment.[220] FERC compiled all of the NERC resources that it relied on in the NOPR into a single appendix that is viewable separately on the FERC website.[221] FERC stated that despite these efforts, events involving IBRs, "have continued to occur in areas of the country with large penetrations of IBRs."[222]

FERC declared that the existing Reliability Standards do not adequately address several risks that IBRs pose to the reliable operation of the Bulk-Power System.[223] First, the Reliability Standards do not ensure that transmission planning and operating entities receive accurate and complete data regarding IBR location, capacity, telemetry, steady-state, dynamic and short circuit modeling information,

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215. *Id.* at 74,542 n.9.

216. 87 Fed. Reg. 74,541, at 74,542 n.10 (citing NERC, RELIABILITY GUIDELINE: BPS-CONNECTED INVERTER-BASED RESOURCE PERFORMANCE 11 (2018), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf.

217. 87 Fed. Reg. 74,541, at 74,542.

218. *Id.* at 74,542-43.

219. *Id.* at 74,547.

220. *Id.* at 74,545.

221. 87 Fed. Reg. 74,541, at 75,546 (citing FERC, *Table of Cited NERC IBR Resources* (RM22-12-000), https://www.ferc.gov/media/table-cited-nerc-ibr-resources-rm22-12-000).

222. *Id.* at 74,547.

223. *Id.* at 74,547-48.

control settings, ramp rates, equipment status, or disturbance analysis data (collectively, IBR data).[224] Second, the Reliability Standards do not ensure that transmission planning and operating entities receive and validate sufficient unregistered IBR modeling data and parameters or IBR-DER aggregate modeling data and parameters to ensure reliability.[225] Third, "[t]he Reliability Standards do not ensure that planning and operational studies assess the performance and behavior . . . of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR-DERs in the aggregate."[226] Finally, the Reliability Standards do not adequately address four issues related to IBR performance: (1) IBR frequency ride through; (2) voltage ride through; (3) post-disturbance IBR ramp rate interactions; or (4) IBR phase lock loop synchronization.[227]

C. Proposed Directives

FERC proposed, "pursuant to section 215(d)(5) of the FPA and §39.5(f) of its regulations, . . . to direct NERC to develop new . . . or modified Reliability Standards that address the following specific matters for IBRs:" data sharing; model validation; planning and operational studies; and performance requirements.[228] FERC also proposed to direct NERC to submit a compliance filing within 90 days of the final rule to explain NERC's process of developing new or modified Reliability Standards to that would address FERC's concerns.[229] FERC sought comments on directing NERC to use a staggered approach, which would result in NERC submitting new or modified Reliability Standards in three stages to account for the scope of work anticipated and provide target dates as an incentive.[230]

1. Data Sharing

FERC preliminarily found that "the current Reliability Standards are inadequate to ensure that sufficient data of registered IBRs and unregistered IBRs, and IBR-DER data in the aggregate is provided to the registered entities responsible for planning, operating, and analyzing disturbances on the Bulk-Power System."[231] FERC identified several effective and enforceable Reliability Standards that do not require NERC-registered entities to provide data that represents the behavior of both individual and aggregate IBRs "at a sufficient level of fidelity for planners and operators to accurately plan, operate, and analyze disturbances on the Bulk-Power System."[232] To address this reliability gap, FERC proposed to direct NERC to ensure that the new or modified Reliability Standards require IBRs to

224. *Id.* at 74,548.
225. 87 Fed. Reg. 74,541, at 74,549
226. *Id.* at 74,552.
227. *Id.* at 74,554-55.
228. *Id.* at 74,555.
229. 87 Fed. Reg. 74,541, at 74,556.
230. *Id.*
231. *Id.*
232. *Id.*

"provide the registered entities responsible for planning and operating the Bulk-Power System with accurate data on registered IBRs.[233]

> FERC also proposed to direct NERC to ensure that the new or modified Reliability Standards require transmission owners to provide to transmission planning entities the modeling data and parameters for unregistered IBRs in their footprints where the unregistered IBRs individually or in the aggregate materially affect the reliable operation of the Bulk-Power System.[234]

FERC further proposed to direct NERC to ensure that the new or modified Reliability Standards require distribution providers to provide to transmission planning entities the "modeling data and parameters for IBR-DERs in the aggregate connected in its distribution provider area."[235]

2. Model Validation

FERC preliminarily found that the existing Reliability Standards are inadequate to ensure that transmission planners and operators receive accurate data relating to generator behavior during normal conditions or during various grid conditions or disturbances.[236] FERC further preliminarily found that the existing Reliability Standards do not require transmission planners and operators to validate and update resource models with data that reflects the actual generator behavior during various operating conditions.[237] Finally, FERC preliminarily found that the existing Reliability Standards do not require transmission planners and operators to have interconnection-wide planning and operational models that represent all generation resources, including IBRs, synchronous generation resources, and load resources.[238] FERC also preliminarily found that there is a coordination gap among registered entities that build and verify interconnection-wide cases.[239]

FERC proposed to direct NERC to develop and submit "new or modified Reliability Standards that would ensure that all necessary models are validated."[240] "Such validation would require a comparison of predicted registered IBR and unregistered IBR performance and behaviors with their actual performance and behavior and a similar comparison of IBR-DER performance and behavior "in the aggregate."[241] FERC further proposed that new or modified Reliability Standards require the use of industry approved IBR models.[242]

233. 87 Fed. Reg. 74,541, at 74,556-57.
234. *Id.* at 74,557.
235. *Id.*
236. *Id.*
237. 87 Fed. Reg. 74,541, at 74,557.
238. *Id.*
239. *Id.* at 74,558.
240. *Id.* at 74,557.
241. 87 Fed. Reg. 74,541, at 74,558.
242. *Id.*

3. Planning and Operational Studies

FERC preliminarily found that the current Reliability Standards do not require planning and operational studies to use "validated IBR modeling and operational data" to ensure that those studies "account for the actual behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR-DERs in the aggregate."[243] FERC proposed to direct NERC to develop and submit new or modified Reliability Standards that would require planning assessments to include the "study and evaluation of performance and behavior of individual and aggregate registered IBRs and unregistered IBRs, as well as IBR-DERs in the aggregate, under normal and contingency system conditions."[244] FERC proposed that those planning assessments would include the ride through performance of registered IBRs and unregistered IBRs, as well as IBR-DERs in the aggregate.[245]

4. Performance Requirements

FERC preliminarily found that "the Reliability Standards should require registered IBRs to ride through system disturbances to support essential reliability services."[246] FERC also preliminarily found that the currently effective Reliability Standards do not require registered IBR "frequency ride through performance during system disturbances."[247] FERC next preliminarily found that the currently effective Reliability Standards do not "adequately address registered IBR protection and controls settings to allow for voltage ride through during system disturbances."[248] FERC also preliminarily found that the current Reliability Standards do not sufficiently "address registered IBR post-disturbance ramp rates following momentary cessation such that Bulk-Power System transient and frequency stability is supported during the system disturbances."[249] FERC finally preliminarily found that the current Reliability Standards do not require that "all generation resources maintain voltage phase angle synchronization with the Bulk-Power System grid voltage during a system disturbance."[250]

FERC proposed to direct "NERC to ensure that the proposed new or modified Reliability Standards clearly address and document the technical differences and technical capabilities between registered IBRs and synchronous generation resources" so that the registered IBRs would provide support for essential reliability services.[251] FERC proposed that the Reliability Standards should "require registered IBR generator owners and registered IBR generator operators to use appropriate settings (i.e., inverter, plant controller, and protection) that will assure frequency ride through during system disturbances" while permitting "registered IBR

243. *Id.*
244. *Id.*
245. 87 Fed. Reg. 74,541, at 74,558.
246. *Id.* at 74,559.
247. *Id.* at 74,559.
248. *Id.* at 74,560.
249. 87 Fed. Reg. 74,541, at 74,560.
250. *Id.* at 74,557.
251. *Id.* at 74,559.

tripping only to protect the registered IBR equipment."[252] FERC next proposed that the Reliability Standards should "require registered IBR generator owners and registered IBR generator operators to use appropriate and coordinated registered IBR protection and controls settings that will allow for voltage ride through during system disturbances" while permitting "registered IBR tripping only when necessary to protect the registered IBR equipment."[253] FERC acknowledged that some IBRs currently in operation may not be able to meet these requirements and required mitigation as necessary to accommodate any reliability impacts that the existing facilities may pose to the Bulk-Power System.[254] FERC also proposed that the Reliability Standards should "require registered IBR post-disturbance ramp rate not to be restricted or to artificially interfere with the resource returning to pre-disturbance output level in a quick and stable manner after a Bulk-Power System fault event."[255] FERC finally proposed that the Reliability Standards should "require registered IBRs to ride through any conditions not addressed by the proposed Reliability Standards that address frequency or voltage ride through phase lock loop loss of synchronism."[256]

D. Deadlines

Public comments are due to FERC on February 6, 2023, and reply comments are due to FERC on March 6, 2023.[257] FERC Commissioner Danly concurred with the NOPR, noting his concerns that NERC may not be able to respond to reliability challenges quickly enough.[258]

X. MIDCONTINENT INDEP. SYS. OPERATOR, INC. 179 FERC ¶ 61,124

On May 18, 2022, FERC issued an order accepting proposed revisions to the Midcontinent Independent System Operator, Inc. (MISO) Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).[259] The revisions permit costs of a Multi-Value Project (MVPs)[260] portfolio to be allocated "entirely to either the MISO Midwest MVP Cost Allocation Subregion or the MISO South MVP Cost Allocation Subregion," if MISO determines that the portfolio primarily benefits only a single subregion.[261] FERC found that allocating costs of MVPs by

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252. *Id.*
253. 87 Fed. Reg. 74,541, at 74,560.
254. *Id.*
255. *Id.*
256. *Id.*
257. 87 Fed. Reg. 74,541, at 74,561.
258. *Id.* at 74,563 (Danly, Comm'r, concurring).
259. Midcontinent Indep. Sys. Operator, Inc., 179 FERC ¶ 61,124 at P 1 (2022).
260. *Id.* at P 1. "A Multi-Value Project is one or more Network Upgrades that address a common set of Transmission Issues and satisfy conditions listed in… MISO's Tariff." *Id.* at P 1 n.4.
261. *Id.* at P 1.

subregion comports with the cost causation principle[262] and with the Cost Allocation Principles of Order No. 1000.[263] FERC also approved the proposed process for determining whether a "portfolio provides benefits system-wide or" only subregionally, which turns on the nature of the transmission issue which is addressed by the MVP portfolio.[264]

Commissioner Christie issued a separate opinion concurring in the order. Commissioner Christie stated that he shared the concerns raised by certain parties concerning whether it is just and reasonable to allocated MVP costs within subregions on a postage stamp basis.[265] However, Commissioner Christie nevertheless concurred in the order because "(i) the Organization of MISO States, Inc. (OMS) supported the filing; (ii) MISO promised to seriously consider replacing the postage stamp cost allocation method with a more granular cost allocation method;" and "(iii) the postage stamp cost allocation method is MISO's current MVP cost allocation method," and it has not been shown to be unjust and unreasonable.[266]

XI. CON. EDISON CO. OF N.Y., INC. V. FERC, 45 F.4TH 265 (D.C. CIR. 2022)

On August 9, 2022, the United States Court of Appeals for the District of Columbia issued an opinion in the combined cases of Consolidated Edison Company of New York, Hudson Transmission Partners, LLC, et al., and the New Jersey Board of Public v FERC.[267] This decision by the Court concerned the cost responsibility for upgrades to New Jersey's grid to prevent short circuits and upgrade the aging system into a more resilient system.[268]

"PJM Interconnection, LLC ("PJM"), the Regional Transmission Operator responsible for New Jersey's grid, authorized a series of upgrades to" the grid to resolve these issues and assigned the cost for these transmission projects using its Federal Energy Regulatory Commission (FERC or the Commission) approved ex-ante cost allocation methodology, the DFAX methodology.[269] The DFAX Methodology uses a flow-based methodology to allocate costs based on the projected use of the facilities.[270] Based on the DFAX methodology, PJM assigned most of the costs of these projects to Consolidated Edison Company of New York (ConEd), Hudson Transmission Partners, LLC, and other Merchant Transmission Facilities (MTFs) (collectively, New York Parties).[271] The New York Parties then

262. K N Energy, Inc. v. FERC, 968 F.2d 1295 (D.C. Cir. 1992) (The cost causation principle requires that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them.") *Id.* at 1300.

263. *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, 136 FERC ¶ 61,051 (2011), *order on reh'g*, 139 FERC ¶ 61,132, *order on reh'g and clarification*, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.,* S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41 (D.C. Cir. 2014).

264. 179 FERC ¶ 61,124, at P 70.

265. *Id*. at P 3 (Christie, Comm'r, concurring).

266. *Id*.

267. Con. Edison Co. of N.Y., Inc. v. FERC, 45 F.4th 265 (D.C. Cir. 2022).

268. *Id.* at 270.

269. *Id*.

270. *Id*. at 272-73.

271. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 272-73.

filed numerous FPA section 206 complaints arguing that PJM's use of the DFAX methodology and the elements that went into the DFAX calculation were unjust and unreasonable methods to allocate the costs of these projects.[272] FERC rejected these complaints and stated that the DFAX methodology was just and reasonable and it was permissible to allocate the costs to the New York entities.[273] After FERC denied the complaints and PJM reallocated costs to the MTFs, they converted their firm withdrawal rights to non-firm withdrawal rights with firm point-to-point service.[274] The New Jersey Board of Public Utilities (the "Board of Public Utilities") intervened and protested these withdrawals and conversions, arguing that the MTFs were still receiving the same services but were not paying for it.[275]

On the first issue of whether using the DFAX methodology to allocate the costs of projects that addressed short circuits, the Court found that the Commission's explanation was unsatisfactory because of the Commission's recent departure from using the DFAX methodology to address non-flow-based problems.[276] In *Artificial Island*, the Commission justified PJM's departure from the DFAX methodology for another cost allocation methodology because it better captured the beneficiaries of an upgrade to solve a non-flow-based problem.[277] Thus, the beneficiaries of the project are different. The Court found that the Commission had yet to explain why projects built to resolve stability issues are analytically unique from the non-flow-based transmission projects central to the *Artificial Island* proceeding.[278] The Court, therefore, remanded back to FERC to provide a more reasoned explanation on this issue or propose another methodology to allocate cost for short circuit issues.[279]

The second issue the New York Parties advanced was the assumptions based on the de minimis threshold, netting, and peak-load assumption were improper.[280] The Court found that the Commission's justification for the de minimis threshold was unpersuasive and that the de minimis threshold unlawfully preferred larger zones at the expense of smaller zones.[281] Concerning netting, the Court found that the Commission's reasoning was justifiable in that netting captured the benefits of counterflow, but the Court stated the Commission could still revisit that conclusion at a future date.[282] Regarding the use of peak load assumptions, the Court found that the FERC reasonably explained why PJM should study all entities using their deliverable rights at peak load because system reliability is paramount to PJM.[283]

272. *Id.* at 276.
273. *Id.* at 289.
274. *Id.* at 277, 289.
275. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 277.
276. *Id*. at 278.
277. Pub. Serv. Elec. & Gas Co. v. FERC, 989 F.3d 10, 13 (D.C. Cir. 2021).
278. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 280.
279. *Id.* at 281.
280. *Id.*
281. *Id*. at 280-83.
282. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 283-84.
283. *Id*. at 284-85.

Thus, it was proper for PJM to plan for the worst-case scenario even if some grid users may not use their full deliverable rights at that time.[284]

The last challenge by the New York parties was FERC's interpretation of PJM's tariff was unreasonable because they argued that PJM's tariff requires a departure from the pro forma cost allocation when it produces unjust and unreasonable results.[285] In contrast, FERC argued that PJM could not do this. The Court held that the Commission's interpretation of PJM's tariff was permissible.[286]

The Court dismissed the three arguments made by the Board of Public Utilities. The Court dismissed the Board of Public Utilities' first claim that ConEd should share the costs of PJM transmission projects.[287] As the Court held that FERC had correctly determined that Order 1000 Cost Allocation Principle 4, the termination agreement, and the Joint Operating Agreement between PJM and the New York Independent System Operator did not mandate the allocation of costs to ConEd.[288] On the second issue, of whether the MTFs election of using firm point-to-point service with non-firm withdrawal rights is similar to firm withdrawal the Court held that while it is a "powerful argument," it was not preserved by the Board of Public Utilities and thus the Court lacked jurisdiction to hear the argument.[289] Lastly, the Court held that the Commission did consider the total effect when it did not allocate costs to the New York Parties.[290]

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284. *Id*. at 285.
285. *Id.*
286. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 286.
287. *Id*. at 287-88.
288. *Id*. at 289.
289. *Id.*
290. *Con. Edison Co. of N.Y., Inc.*, 45 F.4th at 290.