

REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant electric regulatory orders issued by the Federal Energy Regulatory Commission (the Commission or FERC), as well as several court issuances of national import, in 2017. As described in the summary in section I.A., FERC lacked a quorum for a significant part of 2017 due to a retirement and two Commissioners’ term expirations during a presidential transition year. Given the lack of quorum, this report also includes summaries of FERC actions taken during the period of time with no quorum.*

The presidential transition of 2017 ushered in a new Secretary of Energy, Secretary Rick Perry, formerly the longest-serving governor of Texas. As discussed in section I.E., Secretary Perry submitted to the Commission a proposed rule on grid reliability and resilience pricing (Proposed Rule). The timeline for Commission consideration of the Proposed Rule directed by the Secretary would have resulted in Commission action before the end of 2017; however, as discussed herein, the Commission, with the Secretary’s approval, acted on the Proposed Rule on January 8, 2018 in an Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures. While this action was taken in 2018, an accounting of significant electricity developments in 2017 would be incomplete without mention of the Commission’s Order on the Proposed Rule. In its January 8, 2018 Order, the Commission found “[n]either the Proposed Rule nor the record in this proceeding has satisfied the threshold statutory requirement [of section 206 of the Federal Power Act (FPA)] of demonstrating that the [regional transmission organization] RTO/[independent system operator] (ISO) tariffs are unjust and unreasonable.”¹ The Commission also found that remedy afforded by the Proposed Rule was not found to be “just and reasonable” nor was it found not to be “unduly discriminatory or preferential.”² Even though the Commission terminated the rulemaking docket, it initiated a new proceeding to explore resilience issues in the RTOs/ISOs.³

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1. *Grid Reliability and Resilience Pricing*, 162 F.E.R.C. ¶ 61,012 at P 15 (2018).

2. *Id.* at P 16.

3. *Id.* at PP 17-18.

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I. RULEMAKINGS AND POLICY STATEMENT

A. *Agency Operations in the Absence of a Quorum*

Section 401(e) of the Department of Energy (DOE) Organization Act requires a quorum of three commissioners for the transaction of business.⁴ The FERC lost an official quorum when FERC Chairman Norman Bay retired effective February 3, 2017. Accordingly, FERC issued an Order Delegating Further Authority to the Staff in the Absence of a Quorum, explaining its ongoing regulatory obligations and responsibility to continue administering its duties under its authorizing statutes “in an effective and efficient manner consistent with the public interest.”⁵ Specifically, to ensure that rate filings under the FPA and Natural Gas Act (NGA) do not go into effect by operation of law in the absence of Commission action, the delegation order assigned certain authority to its staff until the quorum was restored.⁶ The FERC delegated to the Director of the Office of Energy Market Regulation (OEMR) the authority to (1) accept, suspend, and make effective (subject to refund) filings under section 4 of the NGA, section 205 of the FPA, and section 6(3) of the Interstate Commerce Act (ICA), and (2) to set those filings for hearing and settlement judge procedures.⁷ The FERC also delegated to staff the authority to institute a proceeding pursuant to section 206 of the FPA to protect the interests of consumers for initial rates or rate decreases filed pursuant to section 205 of the FPA, given that suspension and refund protection are not available.⁸ The FERC delegated to staff the authority to extend time for action on matters where time extensions are permitted by statute and to take appropriate action on uncontested filings made pursuant to section 4 of the NGA, section 205 of the FPA, and section 6(3) of the ICA seeking waivers of terms and conditions

4. 42 U.S.C. § 7171(e) (2012).

5. *Agency Operations in the Absence of a Quorum*, 158 F.E.R.C. ¶ 61,135 at P 1 (2017) [hereinafter *Quorum Order*].

6. *Id.* at PP 1-2 (explaining that such delegated authority would not extend beyond fourteen days following the date a quorum is reestablished).

7. *Id.* at P 4; 15 U.S.C. § 717c (2012); 16 U.S.C. § 824d (2012); 49 App. U.S.C. § 6(3) (1988).

8. *Quorum Order*, *supra* note 5, at 4.

in tariffs and service agreements.⁹ Finally, FERC also delegated to the Director of OEMR the authority to accept uncontested settlements filed pursuant to Rule 602 of the Commission's Rules of Practice and Procedure.¹⁰ The Commission regained a quorum on August 10, 2017.¹¹ The delegation of authority period ended fourteen days thereafter on August 24, 2017.¹²

B. State Policies and Wholesale Markets Operated by ISO-NE, NYISO, and PJM

Operating with no quorum, Commission staff convened a two-day technical conference on May 1, 2017, to discuss the interplay between policy goals of states and that of wholesale markets operated by ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM) (collectively, the Eastern RTOs/ISOs).¹³ As a general background principle, the Commission noted that competitive wholesale markets are designed, select resources based on principles of operational and economic efficiency without specific regard to resource type.¹⁴ The conference was designed to explore how the competitive wholesale markets can select resources of interest to state policy makers while preserving the benefits of regional markets and economic resource selection.¹⁵ After the technical conference, the Commission invited industry comments.¹⁶ The Commission identified the following five potential paths forward with respect to the interplay between state policy goals and the wholesale markets to guide the discussion:

- Path 1 – *Limited or No Minimum Offer Price Rule (MOPR)*: “an approach that would either not apply the [MOPR] to state-supported resources, or limit application of the [MOPR] to only state-supported resources where federal law preempts the state action providing that support.”¹⁷
- Path 2 – *Accommodation of State Actions*: “an approach that would accommodate state policies that provide out-of-market support with the operation of the wholesale markets by allowing state-supported resources to participate in those markets and, when relevant, obtain capacity supply obligations, subject to adjustments necessary to maintain certain wholesale market prices consistent with the market

9. *Id.* at PP 5-6.

10. *Id.* at P 7; Submission of Settlement Offers, 18 C.F.R. § 385.602 (1982).

11. See Press Release, FERC, FERC Set to Resume Open Meeting Schedule (Aug. 10, 2017).

12. *Id.*

13. Supplemental Notice of Technical Conference, *State Policies & Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., & PJM Interconnection, L.L.C.*, 82 Fed. Reg. 24,966 (May 31, 2017).

14. *Id.*

15. *Id.* at 2.

16. Notice Inviting Post-Technical Conference Comments, *State Policies & Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., & PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 23, 2017).

17. *Id.* at 1.

results that would have been produced had those resources not been state-supported.”¹⁸

- Path 3 – *Status Quo*: “an approach that would rely on existing tariff provisions applying the [MOPR] to some state-supported resources, and continuing case-by-case litigation over the specific line to be drawn [for the MOPR].”¹⁹
- Path 4 – *Pricing State Policy Choices*: “an approach in which state policies, to the extent possible, would value the attributes . . . or externalities . . . that states are targeting in a manner that can be readily integrated into the wholesale markets in a resource-neutral way. For those state policies that cannot be readily valued and integrated into the wholesale markets, Path 4 would also require consideration of what, if anything, the Commission should do to address the market impacts of these state policies. For instance, other approaches for these state policies may include accommodation, application of the [MOPR], or an exemption from the [MOPR].”²⁰
- Path 5 – *Expanded MOPR*: “an approach that would minimize the impact of state-supported resources on wholesale market prices by expanding the existing scope of the [MOPR] to apply to both new and existing capacity resources that participate in the capacity market and receive state support.”²¹

Commenters were “invited to address these paths, to describe alternative potential paths forward in the wholesale markets, or to describe individual solutions.”²² More than eighty parties filed post-technical conference comments in the docket.²³

C. FERC Policy Statement on Hydropower License Terms

On October 19, 2017, the Commission issued a policy statement on establishing license terms for hydroelectric projects.²⁴ Under section 6 of the FPA, hydropower licenses are issued for a term not to exceed fifty years, and section 15(e) states that any “new license” will be issued for a term that FERC determines to be in the public interest between thirty and fifty years.²⁵ For hydroelectric projects located at federal dams, FERC’s existing policy set a fifty-year term for licenses.²⁶ For hydroelectric projects at non-federal dams, FERC’s existing policy

18. *Id.*

19. *Id.* at 2.

20. *Id.*

21. Docket No. AD17-11-000, at 2.

22. *Id.* at 2.

23. *Id.*

24. *Policy Statement on Establishing License Terms for Hydroelectric Projects*, 82 Fed. Reg. 49,501 (Oct. 26, 2017) (to be codified at 18 C.F.R. pts. 4, 5, 16).

25. *Id.*; 16 U.S.C. § 799 (2012); 16 U.S.C. § 808(e) (2012). A “new license” refers to a license issued to replace a project’s expiring license.

26. *City of Danville, Va.*, 58 F.E.R.C. ¶ 61,318, at p. 62,020 (1992) (citing *Little Falls Hydroelectric Ass’ns*, 27 F.E.R.C. ¶ 61,376 (1984)).

sets three different term limits.²⁷ Recognizing the need for reinterpretation of this licensure authority, FERC established a new forty-year default license term for original and new licenses for hydropower projects located at non-federal dams.²⁸ Under certain circumstances, however, the Commission may issue shorter or longer license terms in order to improve efficiency and ensure safety.²⁹

D. Uplift Cost Allocation and Transparency in Markets Operated by RTOs and ISOs

On January 19, 2017, the Commission issued a Notice of Proposed Rulemaking (NOPR) to address “potentially unjust and unreasonable rates resulting from allocating real-time uplift costs to deviations [from day-ahead market schedules].”³⁰ The Commission stated that costs should be allocated to “only those market participants whose transactions are reasonably expected to have caused the real-time uplift.”³¹ The Commission NOPR proposed that RTOs and ISOs would divide uplift costs into, at minimum, capacity and congestion-management categories, and then allocate costs only to participants’ net harmful deviations.³² Accordingly, costs would not be allocated to deviations in response to real-time dispatch instruction from the RTOs or ISOs.³³ Real-time uplift allocation to deviations would be “settled using hourly uplift rate calculations.”³⁴ The Commission also preliminarily found current practices for reporting “uplift payments, operator-initiated commitments, and transmission constraint penalty factors” to be unjust and unreasonable, and found that the resulting “lack of transparency with respect to transmission constraint penalty factors may hinder a market participant’s ability to . . . hedge energy market transactions.”³⁵ Consequently, the Commission proposed that each RTO and ISO report: (1) “total uplift payments for each transmission zone on a monthly basis, broken out by day and uplift category;” (2) “total uplift payments for each resource on a monthly basis;” (3) “the [megawatts] of operator-initiated commitments in or near real-time and after the close of the day-ahead market, broken out by zone and commitment reason;” and (4) “list in its tariff the transmission constraint penalty factors, the circumstances under which they can set LMPs (locational marginal prices), and the procedure by which they can be temporarily changed.”³⁶ The Commission also sought input on “whether additional reporting of transmission outages should be required,”

27. *Id.* at p. 62,021; *Consumers Power Co.*, 68 F.E.R.C. ¶ 61,077, at p. 61,384 (1994).

28. 68 F.E.R.C. ¶ 61,077, at p. 61,384. This policy does not apply to pilot hydrokinetic projects, which have terms of up to five years. See FERC, LICENSING HYDROKINETIC PILOT PROJECTS (2008).

29. 82 Fed. Reg. 49,501, *supra* note 24, at 49,503.

30. Notice of Proposed Rulemaking, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 F.E.R.C. ¶ 61,047 at P 35 (2017) (to be codified at 18 C.F.R. pt. 35).

31. *Id.*

32. *Id.* at PP 40-48.

33. *Id.* at P 48.

34. *Id.* at P 35.

35. 158 F.E.R.C. ¶ 61,047 at P 5.

36. *Id.* at P 82.

whether “certain classes of market participants are [currently] prohibited from obtaining the network model in certain RTOs/ISOs,” and whether ninety days is sufficient to allow RTOs and ISOs to develop conforming tariff language.³⁷

E. Grid Reliability and Resilience Pricing

On September 28, 2017, pursuant to section 403 of the DOE Organization Act, Secretary of Energy Rick Perry proposed a rule (“Proposed Rule”) on grid reliability and resilience pricing for consideration by the Commission.³⁸ The FERC was instructed to take action on the Proposed Rule within sixty days of its publication in the Federal Register, which occurred on October 10, 2017.³⁹ Thus, on October 2, 2017, the Commission issued its Notice Inviting Comments on the Proposed Rule, and on October 4, 2017, Commission staff issued a request that commenters responding to the Proposed Rule also address several questions related to, among other things, the need for reform, eligibility, implementation, and rates.⁴⁰ In his directive to consider the Proposed Rule, Secretary Perry cited the 2014 Polar Vortex and other weather-related events, including Superstorm Sandy and 2017 weather events, as justification for immediate action on grid reliability and resilience.⁴¹ The Proposed Rule itself includes rules on Commission-approved ISOs and RTOs to “ensure that certain reliability and resilience attributes of electric generation resources are fully valued.”⁴² Specifically, the Proposed Rule allows each Commission-approved ISO and RTO to establish a reliability and resilience rate for the purchase of electric energy and the recovery of costs and a return on equity [ROE] to ensure that each eligible resource is “fully compensated for the benefits and services it provides to grid operations, including reliability, resiliency and on-site fuel-assurance, and that each eligible resource recovers its fully allocated costs and a fair return on equity [(ROE)].”⁴³ Resources eligible for the rate are those located within a Commission-approved ISO or RTO, able to provide “essential energy and ancillary reliability services,” and must also have a ninety-day fuel supply on site compliant with all applicable environmental laws, rules and regulations.⁴⁴ The Commission received more 1,500 submissions on the Proposed Rule.⁴⁵ In advance of the DOE’s requested deadline for Commission action, FERC Chairman McIntyre proposed a thirty-day extension on December 7, and Secretary Perry granted the thirty-day extension on December 8, making Commission final action on the Proposed Rule due on January 10, 2018.⁴⁶

37. *Id.* at PP 100-01, 103.

38. *Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017) (to be codified at 18 C.F.R. pt. 35).

39. *Id.* at 46,945.

40. Notice Inviting Comments, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 4, 2017).

41. 82 Fed. Reg. 46,940, *supra* note 38, at 46,945.

42. *Id.* at 46,941.

43. *Id.* at 46,948.

44. *Id.*

45. *See generally* *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000.

46. Letter from the Secretary of Energy Rick Perry to the Honorable Kevin J. McIntyre, FERC Chairman (Dec. 8, 2017).

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ELECTRICITY COMMITTEE

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II. RTO/ISO DEVELOPMENTS

A. ISO-NE

On October 6, 2017, the Commission issued an order rejecting the New England Transmission Owners' (NETOs) compliance filing seeking to reinstate the NETOs' base ROE of 11.14% that was in effect for the before the issuance of now-vacated Opinion No. 531.⁴⁷ In that case, NETO customers originally sought review of the ROE at the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), and the court vacated and remanded the opinion, finding that the Commission did not satisfy the requirements of section 206 to first find that the NETOs ROE was unjust and unreasonable before implementing the new ROE, and that the Commission had not adequately explained why the upper midpoint of the zone of reasonableness produced a just and reasonable ROE.⁴⁸ On remand, the Commission found that the upper midpoint for the NETOs was 10.57% and required the NETOs to make a compliance filing reflecting the new ROE.⁴⁹

On June 5, 2017, while the remand order remained pending, the NETOs submitted an amended compliance filing (NETO Compliance Filing) arguing that, because the court vacated Opinion No. 531, the NETOs should be allowed to collect their pre-Opinion No. 531-A ROE of 11.14% to "document[] the legal effect of the Court's decision in *Emera Maine v. FERC*," to "return the parties to the *status quo ante*."⁵⁰ The Commission rejected the NETO Compliance Filing and ultimately found that the NETOs' new ROE should be set at the "upper midpoint of the zone of reasonableness."⁵¹ On appeal, the NETOs argued that FERC's orders must be vacated because it failed to find that the existing ROE was unjust and unreasonable before setting a new ROE.⁵² The court held that FERC (1) did not meet the first requirement of section 206 because it failed to demonstrate the unlawfulness of the NETOs' base ROE before setting a new rate, and (2) FERC failed to provide any reasoned basis for selecting 10.57% as the new base ROE.⁵³

A group of transmission owners petitioned for review of FERC's orders approving ISO-NE's Order No. 1000 compliance filings, objecting to FERC's determination that the right of first refusal provision must be removed from the Transmission Operating Agreement (TOA).⁵⁴ In determining whether FERC overcame

47. *ISO New England, Inc. v. Bangor Hydro-Elec. Co.*, 161 F.E.R.C. ¶ 61,031 (2017) [hereinafter NETO Compliance Order]. The NETOs are: (1) Emera Maine (f/k/a Bangor Hydro-Electric Co.); (2) Central Maine Power Co.; (3) Eversource Energy Service Co. (f/k/a Northeast Utilities Service Co.) on behalf of the Connecticut Light & Power Co., NSTAR Electric Co., Western Massachusetts Electric Co., and Public Service Co. of New Hampshire; (4) New England Power Co. d/b/a National Grid; (5) New Hampshire Transmission LLC; The United Illuminating Co.; (6) Unital Energy Systems, Inc. & Fitchburg Gas & Electric Light Co.; and (7) Vermont Transco LLC. *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 F.E.R.C. ¶ 61,234 (2014), vacated in part by *Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017)), *order on paper hearing*, Opinion No. 531-A, 149 F.E.R.C. ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 F.E.R.C. ¶ 61,165 (2015).

48. *Maine*, 854 F.3d at 30.

49. NETO Compliance Order, *supra* note 47, at P 4.

50. *Id.* at P 11.

51. *Id.* at P 3. Also note that on Nov. 6, 2017, the NETOs filed a request for rehearing.

52. *Id.* at P 5.

53. *Maine*, 854 F.3d at 25, 32.

54. *ISO New England Inc.*, 143 F.E.R.C. ¶ 61,150 (2013), *on reh'g*, 150 F.E.R.C. ¶ 61,209 at P 114 (2015).

the *Mobile-Sierra* presumption, the court followed the Supreme Court's opinion in *In re Permian Basin Area Rate Cases*, where the court held that a Commission decision may not "properly be set aside merely because the Commission has on an earlier occasion reached another result; administrative authorities must be permitted, consistently with the obligations of due process, to adapt their rules and policies to the demands of changing circumstances."⁵⁵ As such, the court determined FERC's decision was not arbitrary or capricious, but "[r]ather, it was the natural consequence of the new policy adopted in Order No. 1000 to address the changing circumstances identified by the Commission."⁵⁶ The court recognized that FERC made a so-called particularized analysis when it revoked the TOA right of first refusal provision because it found that rights of first refusal: (1) "are generally anticompetitive;" and (2) "would adversely affect transmission development."⁵⁷ In a second and consolidated petition, the New England States Committee on Electricity ("NESCOE") and governmental entities from five of the six New England states including Connecticut, Massachusetts, New Hampshire, Rhode Island, and Vermont, argued that FERC's determination in ISO-NE's Order No. 1000 compliance filings "impermissibly conflicts with and expands on Order No. 1000."⁵⁸ NESCOE stated FERC's order required ISO-NE "must select" a transmission project solution.⁵⁹ The FERC noted, however, that it only meant to convey that if a selection were to occur that such selection "must" be done by ISO-NE, not NESCOE.⁶⁰ As such, FERC also denied the NESCOE's petition for review.⁶¹

On June 28, 2017, the U.S. Court of Appeals for the Second Circuit affirmed a district court decision dismissing claims by Allco Finance Limited (Allco) that the FPA preempted Connecticut's renewable energy solicitation, and that Connecticut's renewable portfolio standard (RPS) program violated the dormant Commerce Clause of the U.S. Constitution.⁶² In that case, Allco, an owner, operator, and developer of solar projects, alleged that the FPA preempted Connecticut law permitting the state's energy regulators to solicit bids for renewable energy generation and then direct Connecticut's utilities to enter into contracts with winning bidders.⁶³ Allco also alleged that Connecticut's RPS program, which "requir[ed] state's utilities to either produce renewable energy themselves or buy renewable energy credits [(RECs)] from other renewable energy producers located within region, violated [the] dormant Commerce Clause."⁶⁴ The Second Circuit Court of Appeals reviewed the district court's dismissal *de novo*.⁶⁵ With respect to Allco's preemption claim, the Court of Appeals found that the lower court's dismissal of

55. *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 784 (1968). *See, e.g.*, *United Gas Pipe Line Co.*, 350 U.S. 348 (1956); *Fed. Power Comm'n v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

56. *Maine v. FERC*, 854 F.3d 662, 670 (D.C. Cir. 2017).

57. *Id.*

58. *Id.* at 666, 673.

59. *Id.* at 673.

60. *Id.*

61. *Maine*, 854 F.3d at 675.

62. *Allco Fin. Ltd. v. Klee*, 861 F.3d 82, 83 (2d Cir. 2017).

63. *Id.* at 97.

64. *Id.* at 86.

65. *Id.* at 96.

Allco's preemption claim was appropriate, because the court determined that the state energy regulator's solicitation program did not compel utilities to accept any bid.⁶⁶ The Court of Appeals also rejected Allco's argument that the solicitations were economically identical to a Maryland program for capacity auctions that the Supreme Court in *Hughes v. Talen Energy Mktg., LLC* because Connecticut's solicitation program results in bilateral contracts between utilities and generators that are subject to FERC review for justness and reasonableness.⁶⁷ The court rejected Allco's third theory that the solicitation exceeded the bounds of PURPA because the court found it settled law that specifying the sizes and types of generators that may bid into the solicitation, as well as specifying fees, lies well within the scope of Connecticut's power to regulate its utilities.⁶⁸ The court also rejected Allco's preemption argument that the solicitation would increase the supply of electricity to Connecticut utilities, reducing the rates that Allco's QFs will receive under PURPA, and that this would have an effect on wholesale prices, infringing on FERC's regulatory authority.⁶⁹ The court determined that such an incidental effect on wholesale prices does not amount to regulation of the interstate wholesale market that infringes on FERC's jurisdiction.⁷⁰ Finally, the court upheld the lower court's dismissal of the dormant Commerce Clause claim with respect to the facility.⁷¹

B. NYISO

On January 27, 2017, FERC approved NYISO's request for approval of revisions to its Market Administration and Control Area Services Tariff (Services Tariff), which were designed to correct perceived pricing inefficiencies in the Installed Capacity (ICAP) market design.⁷² In particular, these inefficiencies related to the treatment of exports from certain localities or "zones" in the New York Control Area.⁷³ As the NYISO explained in its submission, "[e]ach [l]ocality [or zone] in NYISO has a Locational Minimum Installed Capacity Requirement" that must be met by each load serving entity (LSE).⁷⁴ Under current rules, where certain localities are resource-constrained as to import limits, any generator that is confirmed to export is considered to have its full capacity treated as though it is no longer in service; and prices for capacity would increase accordingly.⁷⁵ NYISO proposed to use a methodology called a "Locality Exchange Factor" (LEF) to measure the amount of capacity (megawatts (MW)) from Rest of State that can

66. *Id.* at 98.

67. *Allco*, 861 F.3d at 98-100. *See Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016). Allco also argued that Connecticut's solicitation was inconsistent with the Third Circuit's decision in *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014). The Court of Appeals distinguished *Solomon*, noting that like the scheme at issue in *Hughes*, *Solomon* concerned a scheme that conditioned payments to generator on rates determined in a FERC-approved auction. *Allco*, 861 F.3d at 100.

68. *Allco*, 861 F.3d at 97, 101.

69. *Id.* at 101.

70. *Id.*

71. *Id.* at 108.

72. *N.Y. Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,064 at P 1 (2017).

73. *Id.*

74. *Id.* at P 2.

75. *Id.*

replace the capacity to be exported from the constrained locality.⁷⁶ In approving the revisions, the Commission accepted the proposed LEF mechanism and approved it to be implemented immediately.⁷⁷ It found the mechanism is just and reasonable since it directly addresses the inherent pricing inefficiencies in the current rules as to ICAP prices and market design.⁷⁸ However, the Commission rejected the NYISO's request for a one-year transition period and found that the 80% LEF for the G-7 Locality to be in effect during that period was not based on the same power flow analysis that the NYISO in fact had recommended was the ideal way to account for counter-flows.⁷⁹

On February 3, 2017, FERC ruled in favor of the New York State Public Service Commission (NYSPSC) and a group of New York power authorities and stakeholder groups in a decision that will affect demand side resources operating in the NYISO.⁸⁰ In its order, the Commission granted a blanket exemption for new special case resources (SCRs) from the application of NYISO's buyer-side market power mitigation rules under section 23.4 of NYISO's Services Tariff.⁸¹ The Commission, however, denied, in part, NYSPSC's request to apply the blanket exemption retroactively to SCRs currently subject to mitigation in NYISO's ICAP.⁸² Based on the order, SCRs that wish to participate in NYISO's installed capacity market (ICAP) will no longer be required to comply with buyer-side market power mitigation rules such as price floors.⁸³ In reaching this conclusion, the Commission stated that applying buyer-side market power mitigation rules to SCRs is inconsistent with Commission policy because the rules are intended to address situations in which market power will lead to lower capacity market prices.⁸⁴ According to the Commission, SCRs have "limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices."⁸⁵ After finding that such coordination is unlikely at this time because SCRs are relatively limited and disaggregated, FERC held that the application of section 23.4 of NYISO's Services Tariff is unjust, unreasonable, and unduly preferential under section 206 of the FPA.⁸⁶

C. PJM

In an order issued on January 6, 2017, FERC accepted, subject to condition, PJM's proposed changes to its Open Access Transmission Tariff (OATT) to revise its pricing methodology for the release of excess committed capacity in its Third

76. *Id.* at P 7.

77. 158 F.E.R.C. ¶ 61,064 at P 35.

78. *Id.*

79. *Id.* at P 55.

80. *N.Y. State Pub. Serv. Comm'n*, 158 F.E.R.C. ¶ 61,137 at P 1 (2017).

81. *Id.* at PP 1, 35.

82. *Id.* at PP 1, 30, 35.

83. *Id.* at P 1.

84. *Id.* at 30.

85. 158 F.E.R.C. ¶ 61,137 at P 30.

86. *Id.*

Incremental Auction for the 2017-2018 Delivery Year to “better reflect the potential benefit to load of retaining excess committed capacity.”⁸⁷ PJM, when it began operating under the PJM Capacity Performance rules, procured 10,017 MW of previously uncommitted capacity.⁸⁸ Under then-existing rules, PJM’s pricing methodology for releasing excess capacity would result in PJM offering \$0/MW-day for most, if not all, of the 10,017 MW of excess committed capacity procured through Transition Auctions.⁸⁹ PJM set forth in its filing under section 205 of the FPA that the sales of excess committed capacity at such a low clearing price would be unjust and unreasonable because no revenue is being credited to load for the excess capacity sell back.⁹⁰ PJM’s proposal to address the Third Incremental Auction for the 2017-2018 Delivery Year involved a combination of steps designed to “place a higher value on excess capacity than the current Incremental Auction procedure does.”⁹¹ The FERC accepted PJM’s proposed tariff changes but, in so doing, FERC cautioned that their finding is narrow and applicable for purposes of the Third Incremental Auction for the 2017-2018 Delivery Year only.⁹² However, FERC, while agreeing with PJM’s justification, held that PJM had not sufficiently justified the details of its sell-back offer curve and provided direction as to the required changes, namely that the parameters of the sell offer curve be bound by the lowest price point on PJM’s sell-back offer curve and the Base Residual Auction clearing price.⁹³ The FERC also conditioned its acceptance on PJM allocating the uncleared excess capacity, if any, to load-serving entities as excess commitment credits.⁹⁴ The FERC directed PJM to submit a compliance filing within thirty days of the order’s issuance, effective January 9, 2017.⁹⁵

The Commission ordered Potomac-Appalachian Transmission Highline, LLC (PATH), a joint venture incorporated by Allegheny Power (doing business as FirstEnergy and American Electric Power), to refund more than \$7 million to ratepayers for the canceled PATH project.⁹⁶ Specifically, the Commission upheld most of the \$10 million in refunds recommended in an Initial Decision by the FERC Administrative Law Judge (ALJ), supported the ALJ’s decision to deny recovery of \$6.2 million in advertising, lobbying and “advocacy-building” costs, but reversed the Initial Decision’s rejection of certain legal costs and losses on the sale of properties PATH acquired for the project.⁹⁷ The Commission also found that PATH’s base ROE should be reduced from 10.4% to 8.11%.⁹⁸ In reaching its decision, the Commission rejected arguments that PATH acted imprudently by not

87. *PJM Interconnection, L.L.C.*, 158 F.E.R.C. ¶ 61,010 at P 5 (2017).

88. *Id.*

89. *Id.*

90. *Id.* at PP 9, 14.

91. *Id.* at P 22.

92. 158 F.E.R.C. ¶ 61,010 at P 22.

93. *Id.* at P 23.

94. *Id.* at P 27.

95. *Id.* at P 21.

96. Opinion No. 554, *Potomac-Appalachian Transmission Highline, LLC & PJM Interconnection, L.L.C.*, 158 F.E.R.C. ¶ 61,050 at P 1 (2017) [hereinafter PATH].

97. *Id.* at PP 1, 22.

98. *Id.* at P 270.

seeking early termination of the Project proactively, because, it reasoned, suspension of the project was PJM's call.⁹⁹ The Commission found "the Presiding Judge [ALJ] erred in proceeding under section 205," and placing "the burden on PATH to show that its existing 10.4% ROE is just and reasonable."¹⁰⁰ It did agree, however, with the Presiding Judge's determination that PATH's pre-abandonment 10.4% ROE was unjust and unreasonable, and moreover, that

'a single-asset company [like PATH] . . . whose principal asset is no longer operating . . . ; which has no need to attract capital; and which . . . is . . . guaranteed recovery of virtually all costs associated with its principal asset' – [that] the plant's reduced risk profile require[s] the Commission to reduce its ROE to the lower end of the zone of reasonableness.¹⁰¹

As such, the Commission determined that PATH's "just and reasonable" "abandonment phase" ROE should be set at the median of the lower half of the zone of reasonableness at 8.11%.¹⁰²

Nine organizations, together and separately, petitioned the D.C. Circuit Court for review of FERC's order approving PJM's proposed changes to capacity market rules, which would create "new enforcement mechanisms to ensure resources that made a capacity commitment provided electricity when called upon."¹⁰³ The nine petitioners raised eight challenges to the FERC order, and the court denied each challenge and refused to review the Commission's order.¹⁰⁴ The court held that "FERC balanced the benefits of the revised rules against the increased costs and reached a reasoned judgment."¹⁰⁵ The court found that increased costs can be "just and reasonable" if the costs are warranted.¹⁰⁶ In so doing, the court deferred "to the Commission's weighing of the various considerations and ultimate 'policy judgment.'"¹⁰⁷ In addition, among other things, the court found that the Commission was entitled to approve changes under section 206 in anticipation of the section 205 filing.¹⁰⁸ In several of its findings, including penalty rates for Capacity Performance, the year-round capacity commitment, and the fact that operating limits cannot excuse non-performance in the capacity market, the court accorded the FERC *Chevron* deference in interpreting the FPA.¹⁰⁹ Thus FERC justifiably approved PJM's "new enforcement mechanisms to ensure resources that made a capacity commitment provided electricity when called upon."¹¹⁰

99. *Id.* at PP 193, 203.

100. *Id.* at P 221.

101. PATH, *supra* note 96, at P 264.

102. *Id.* at P 270.

103. *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 660 (D.C. Cir. 2017).

104. *Id.* at 660-62.

105. *Id.* at 660.

106. *Id.* at 662.

107. *Id.* at 662.

108. *Advanced Energy Mgmt. All.*, 860 F.3d at 664.

109. *Id.* at 665.

110. *Id.* at 660.

On July 7, 2017, the D.C. Circuit found that the Commission exceeded its authority under section 205 of the FPA when it directed PJM to make certain revisions to its capacity market buyer mitigation rules.¹¹¹ Specifically, the court reasoned that under section 205 of the FPA, an applicant public utility submits a proposed rate for FERC approval, placing FERC in a “reactive” role to accept or reject an applicant’s submission.¹¹² Section 206, on the other hand, allows FERC to find an existing rate unjust and unreasonable following a complaint or action on its own, and to set an appropriate rate.¹¹³ The court cited precedent holding that FERC may impose minor changes to a section 205 rate proposal on compliance if the applicant utility acquiesces, but FERC may not accept “only half of a proposed rate” or suggest changes that result in “an ‘entirely different rate design.’”¹¹⁴ The court found that FERC’s proposed changes to the PJM rules exceeded FERC’s authority under section 205.¹¹⁵ Further, the court vacated FERC’s underlying orders with respect to the “self-supply exemption, the competitive entry exemption, unit-specific review, and the mitigation period,” and remanded the matter to FERC.¹¹⁶

The decision’s legal analysis highlights limitations on FERC’s ability to direct changes on compliance to proposed rates submitted by a utility or market operator.¹¹⁷

D. MISO

On January 3, 2017, the Commission issued an order accepting, subject to a compliance filing, the Midcontinent Independent System Operator, Inc.’s (MISO) revisions to its Generator Interconnection Procedures (GIP) and *pro forma* Generator Interconnection Agreement (GIA) contained in its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), effective January 4, 2017.¹¹⁸ The proposed revisions seek to improve the timeliness and efficiency of the MISO generator interconnection queue, and, particularly, to address delays resulting from numerous unplanned restudies due to higher-queued projects exiting the queue.¹¹⁹ Specifically, MISO proposed the following revisions:

- (i) implementation of a three-phased Definitive Planning Process (DPP) requiring an interconnection customer to pay a milestone payment prior to entering each phase, and permitting an interconnection customer to withdraw from the queue and receive a refund of its milestone payment at certain “Decision Points;”

111. Petition for Panel Rehearing, *NRG Power Mktg., LLC v. FERC*, Docket Nos. 15-1452, 15-1454 (D.C. Cir. 2017).

112. *Id.* at 114.

113. *Id.*

114. *Id.* at 115. See, e.g., *City of Winnfield v. FERC*, 744 F.2d 871 (D.C. Cir. 1984); *Western Res., Inc. v. FERC*, 9 F.3d 1568 (D.C. Cir. 1993).

115. *NRG Power Mktg. v. FERC*, 862 F.3d 108, 114, 117.

116. *Id.* at 110.

117. See generally *NRG Power Mktg.*, 862 F.3d 109.

118. *Midcontinent Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,003 at P 132 (2017).

119. *Id.* at P 8.

- (ii) revised milestone payment calculations, and clarification that the milestone payments apply towards the interconnection customer's Initial Payment;
- (iii) establishment of a mandatory pre-DPP scoping meeting between the MISO, the interconnection customer, and the transmission owner;
- (iv) implementation of a transition plan;
- (v) more stringent Site Control requirements;
- (vi) inclusion of an informational, *pro forma* services study agreement as an attachment to the Tariff; and
- (vii) added language clarifying when an interconnection customer may request a provisional GIA.¹²⁰

Indianapolis Power & Light (Indianapolis Power) filed a FPA sections 206 and 306 complaint against the MISO on October 21, 2017, alleging that MISO's Operating Reserve Market Tariff (Tariff) is unjust, unreasonable, and unduly preferential as applied to grid-scale battery storage devices.¹²¹ The FERC found that Indianapolis Power had not met its burden to show that MISO's Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff failed to compensate primary frequency response providers.¹²² The FERC also found that Indianapolis Power was not obligated to use the battery storage to provide primary frequency response, and that the Commission has required some generators to provide primary frequency response without compensation in some circumstances.¹²³ Thus, FERC found that Indianapolis Power did not provide evidence that either the Tariff or business practice manual harmed Battery Facility or other fast-responding resources.¹²⁴ However, FERC did find MISO's Tariff to be unjust, unreasonable, and unduly discriminatory or preferential because "it unnecessarily restricts competition by preventing electric storage resources from providing all the services that they are technically capable of providing, which could lead to unjust and unreasonable rates."¹²⁵ The Commission attributed this finding to the Storage Energy Research category limiting the resource's ability to participate only in the regulation market and not allowing it to provide capacity, energy, ramp capability, and contingency reserves.¹²⁶ The FERC gave MISO sixty days to propose revisions to its tariff that accommodate energy storage resources.¹²⁷

On February 2, 2017, the Commission rejected a proposal by the MISO to revise its Tariff to implement the Competitive Retail Solution (CRS).¹²⁸ The purpose of the CRS was to establish a "three-year forward capacity auction (Forward Auction)" and "to better address the reliability needs of Local Resource Zones

120. *Id.* at PP 8, 11-12, 40, 71.

121. *Indianapolis Power & Light Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,107 at P 1 (2017).

122. *Id.* at PP 33, 36.

123. *Id.* at P 36.

124. *Id.*

125. *Id.* at P 2.

126. 158 F.E.R.C. ¶ 61,107 at P 69.

127. *Id.* at P 2.

128. *Midcontinent Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,128 (2017).

(Zones) with Competitive Retail Demand (Competitive Retail Areas).¹²⁹ Other Zones in MISO would have continued to use existing mechanisms, including MISO's existing Planning Resource Auction (Prompt Auction), to demonstrate resource adequacy.¹³⁰ In rejecting the CRS, FERC noted that the "proposed Forward Auction would apply . . . [to] (less than 10%) . . . of the total load within MISO, and would occur more than three years prior to the Prompt Auction, [thus] bifurcating the MISO capacity market."¹³¹ The FERC held that this bifurcated structure, unlike a single market-wide auction, would not co-optimize "zonal capacity requirements subject to the zonal transmission capability constraints and economic supply offers at the time of the auction."¹³² The FERC also feared that the CRS would lead to "significant and unnecessary price volatility in both the Forward [Auction] and the Prompt Auction."¹³³ Finally, FERC found that MISO had "not adequately explained or provided clear Tariff language to demonstrate that the CRS Proposal would reasonably allocate transmission capability across capacity zones and across sub-regions in the MISO footprint between the Forward Auction and the Prompt Auction."¹³⁴

On June 21, 2017, the U.S. Court of Appeals for the Sixth Circuit denied a petition for review challenging FERC orders that determined that Duke Energy and American Transmission Systems were not obligated to pay for projects that MISO approved after the utilities announced their intent to withdraw from MISO, but before they actually left the RTO.¹³⁵ Before reaching the merits of the case, the court found that venue was proper in the Sixth Circuit because all of MISO's members are public utilities under the FPA and at least one of them has its principal place of business in the geographic area of the Sixth Circuit.¹³⁶ In addition, the "spark that lit the controversy was the withdrawal from MISO of Ohio and Kentucky utilities."¹³⁷ The court also noted that the Sixth Circuit offers a less deferential standard of review of FERC orders than the D.C. Circuit and Seventh Circuit, only deferring to Commission decisions when they are based on the agency's factual findings or technical expertise.¹³⁸ At issue in this case was a new provision to the MISO Tariff that provided that ex-members could be charged for certain transmission costs approved before their departure.¹³⁹ The provision was accepted by FERC prospectively.¹⁴⁰ Under the "filed rate" doctrine, the court said the provision could apply to Duke and American Transmission only to the extent it was consistent with those utilities' pre-existing obligations under the Tariff.¹⁴¹

129. *Id.* at P 1.

130. *Id.* at PP 1, 6.

131. *Id.* at P 7.

132. 158 F.E.R.C. ¶ 61,128 at P 8.

133. *Id.* at P 9.

134. *Id.* at P 10.

135. *MISO Transmission Owners v. FERC*, 860 F.3d 837, 839 (6th Cir. 2017).

136. *Id.* at 840.

137. *Id.*

138. *Id.* at 841 (quoting *Cincinnati Gas & Elec. Co. v. FERC*, 724 F.2d 550, 554 (6th Cir. 1984)).

139. *Id.* at 840-41.

140. *MISO Transmission*, 860 F.3d at 840.

141. *Id.* at 841.

The court determined that MISO could only charge Duke and American Transmission for costs incurred by the utilities before they withdrew, pursuant to the provisions of the Tariff in effect at the time.¹⁴²

E. SPP

On October 6, 2017, the Commission rejected, without prejudice, Southwest Power Pool, Inc.'s (SPP) proposed revision to its OATT to implement a cost sharing agreement and allocation of costs among its transmission customers related to two proposed transmission projects.¹⁴³ The two projects were identified in the Joint Operating Agreement transmission planning process between SPP and Associated Electric Cooperative, Inc. (AECI), a non-SPP member rural electric cooperative in Missouri, Iowa, and Oklahoma, to alleviate congestion and operational issues along their shared seam.¹⁴⁴ SPP proposed to allocate its share of the costs of the two projects region-wide to all SPP transmission customers on a load-ratio basis.¹⁴⁵ The FERC rejected SPP's proposal without prejudice, because SPP had not shown that an allocation of the costs to all SPP transmission customers was roughly commensurate with the benefits.¹⁴⁶ The FERC also found unpersuasive SPP's contention that a similar, region-wide allocation was approved for interregional transmission projects between MISO and SPP as part of their compliance with Order No. 1000.¹⁴⁷ The FERC found those projects were allocated to SPP transmission customers only after they were selected in each region's respective regional transmission plan, but the proposed projects with AECI were not subject to interregional transmission coordination and were not selected in SPP's regional transmission plan as interregional transmission facilities.¹⁴⁸ The FERC noted that since the proposed projects existed solely within SPP's or AECI's footprint, they were not eligible for consideration as interregional transmission facilities under their coordination procedures.¹⁴⁹

F. CAISO

The California Independent System Operator Corporation's (CAISO) western Energy Imbalance Market (EIM) is a real-time bulk power trading market, and the "first of its kind in the western United States."¹⁵⁰ The EIM "trades the difference between the day-ahead forecast of power and the actual amount of energy needed to meet demand in each hour."¹⁵¹ If more energy is needed than predicted,

142. *Id.*

143. *Sw. Power Pool, Inc.*, 161 F.E.R.C. ¶ 61, 026 (2017).

144. *Id.* at P 1.

145. *Id.* at P 16.

146. *Id.* at P 39.

147. *Id.* at PP 41-42.

148. 161 F.E.R.C. ¶ 61,026 at P 41.

149. *Id.*

150. *Western EIM FAQ*, CALIFORNIA ISO (Oct. 2017), <http://www.caiso.com/Documents/EnergyImbalanceMarketFAQs.pdf>.

151. Carl Zichella, *Energy Imbalance Market Progress and Why It Matters*, NRDC (May 18, 2017), <https://www.nrdc.org/experts/carl-zichella/energy-imbalance-market-progress-and-why-it-matters>.

the EIM makes up the difference.¹⁵² The EIM launched in 2014, with PacifiCorp as its first member.¹⁵³ NV Energy joined in 2015, Puget Sound and Arizona Public Service joined in 2016, and Portland General Electric joined in 2017.¹⁵⁴ In 2017, several utilities applied to join and are now “pending,” including Idaho Power Company (2018), Powerex (2018), Los Angeles Department of Power and Water (2019), Balancing Authority of Northern California/SMUD (2019), Salt River Project (2020), and Seattle City Light (2020).¹⁵⁵ When these new members become part of the EIM, the EIM will cover eight states (and over eight million ultimate customers) in the U.S., plus a portion of Canada.¹⁵⁶ According to the EIM, significant benefits from increased regional coordination for energy generation and delivery occur in three main areas: (1) “[r]educed costs for utility customers and ISO market participants,” (2) “[r]educed carbon emissions and more efficient use and integration of renewable energy,” and (3) enhanced reliability.¹⁵⁷

On January 27, 2017, the Commission denied in part, granted in part, and dismissed in part rehearing requests of an order issued in 2016 in the longstanding California refund proceeding (FERC Docket Nos. EL00-95 and EL00-98).¹⁵⁸ In the order, the Commission

directed the Respondents [Hafslund Energy Trading L.L.C., Illinova Energy Partners, Inc., MPS Merchant Services, Inc., Shell Energy North America (U.S.), L.P., and APX Inc.] remaining in the instant proceeding to disgorge overcharges and excess amounts they received for all sales during all hours of the Summer Period [a specified period in 2000] during which the market prices were inflated by tariff violations committed by any of the Respondents.¹⁵⁹

In particular, the Commission:

- Dismissed rehearing requests to the extent they raised issues regarding FERC’s findings of tariff violations and their impact on market clearing prices.¹⁶⁰
- Dismissed rehearing requests regarding FERC’s authority under section 309 of the FPA to require the Respondents to disgorge unjust profits.¹⁶¹
- Dismissed rehearing requests regarding FERC’s holding that sellers that engaged in tariff violations were on notice that their transactions may be subject to refund, restitution, and disgorgement

152. *Id.* at 2.

153. Western EIM FAQ, *supra* note 150, at 1.

154. *Id.*

155. WESTERN ENERGY IMBALANCE: JOIN EIM, <https://www.westerneim.com/Pages/JoinEIM.aspx> (last visited Feb. 21, 2018) (see graphic).

156. Zichella, *supra* note 151, at 1.

157. Western EIM FAQ, *supra* note 150, at 1.

158. San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs. into Mkts. Operated by Cal. Indep. Sys. Operator Corp. & Cal. Power Exch., 158 F.E.R.C. ¶ 61,076 at P 1 (2017).

159. *Id.*

160. *Id.* at P 10.

161. *Id.* at PP 17-23.

of profits or other remedy. However, FERC granted in part a rehearing request asserting that certain specified transactions should be separated from other Summer Period transactions.¹⁶²

- Dismissed rehearing requests regarding whether FERC impermissibly imposed vicarious liability on the Respondents.¹⁶³
- Rejected as premature a rehearing request regarding the procedural timelines pertaining to the compliance phase of the proceeding.¹⁶⁴
- Dismissed rehearing requests regarding whether the cost calculation should include all costs and revenues during the entire Summer Period.¹⁶⁵
- Rejected rehearing requests asserting that prices for transactions that were not found to be in violation of then-existing tariffs are entitled to protection under the *Mobile-Sierra* public interest presumption.¹⁶⁶
- Rejected a rehearing request regarding the filer's fuel cost allowance submission.¹⁶⁷

On April 4, 2017, the D.C. Circuit remanded to FERC an issue of contract interpretation raised with the court in a petition for review filed by NextEra Desert Center Blythe, LLC (NextEra).¹⁶⁸ In that case, NextEra initiated a complaint proceeding at FERC in 2015, requesting that the Commission direct the CAISO, pursuant to its tariff, to allocate to NextEra certain Congestion Revenue Rights (CRRs) associated with an interim transmission project to be constructed by Southern California Edison Company (Edison) and paid for by NextEra.¹⁶⁹ The Commission denied the complaint and NextEra's subsequent request for rehearing, on the grounds that contracts between Edison and NextEra "clear[ly] and unambiguous[ly]" barred NextEra from receiving CRRs under the CAISO tariff.¹⁷⁰ On appeal, the D.C. Circuit disagreed that the contracts said so clearly and unambiguously and remanded to FERC the issue whether the contracts in fact permit NextEra to receive CRRs in accordance with the CAISO tariff.¹⁷¹

On April 21, 2017, the U.S. Court of Appeals for the Ninth Circuit granted in part and denied in part a petition for review challenging FERC's calculation of certain refunds arising out of the California energy crisis in 2000 and 2001.¹⁷² Those refunds were levied by FERC on governmental and non-public utilities in a 2005 Ninth Circuit decision, *Bonneville Power Administration v. FERC*.¹⁷³ In response to *Bonneville*, FERC, among other things, "vacated . . . its orders in the

162. *Id.* at PP 30-35.

163. 158 F.E.R.C. ¶ 61,076 at PP 44-52.

164. *Id.* at P 54.

165. *Id.* at PP 57-58.

166. *Id.* at PP 60-64.

167. *Id.* at PP 71-74.

168. NextEra Desert Ctr. Blythe, LLC v. FERC, 852 F.3d 1118, 1120 (D.C. Cir. 2017).

169. *Id.* at 1120-21.

170. *Id.* at 1121 (citing NextEra Desert Center Blythe, LLC v. CAISO, 153 F.E.R.C. ¶ 61,208).

171. *Id.* at 1122.

172. Cal. Pub. Utils. Comm'n v. FERC, 854 F.3d 1136 (9th Cir. 2017).

173. Bonneville Power Admin. v. FERC, 422 F.3d 908, 910 (9th Cir. 2005).

California refund proceeding to the extent . . . they required governmental entities [and/or] non-public utilities to pay refunds.”¹⁷⁴ The FERC further ordered CAISO and California Power Exchange Corporation (CalPX) to complete refund calculations with all entities that participated in the markets and not to redo their refund calculations to remove governmental and non-public utilities.¹⁷⁵ In order to calculate the total refund shortfall, FERC directed CAISO and CalPX to net sales and purchases at hourly intervals, citing provisions of the CAISO and CalPX tariffs as the bases for its directives.¹⁷⁶ In its order, the Ninth Circuit upheld FERC’s orders requiring the CAISO and the CalPX, respectively, to net sales and purchases over hourly intervals rather than for the entire refund period.¹⁷⁷ The court found that FERC did not act arbitrarily and capriciously in determining that the deficit in the CalPX settlement clearing account was properly allocated to net buyers rather than all market participants.¹⁷⁸

On October 30, 2017, FERC issued an order in Docket No. ER17-2237-000, accepting proposed tariff revisions regarding black start capability requested by the CAISO.¹⁷⁹ Black start capability is “the ability of a generating unit or station to begin operating and delivering electric power without external assistance from the electric system.”¹⁸⁰ CAISO requested changes to its tariff effective November 1, 2017 to comply with Order No. 749 of the Commission, which approved the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-005-2.¹⁸¹ CAISO’s existing black start system operates with CAISO entering into black start agreements with participating generators, which currently do not have a reservation fee.¹⁸² CAISO’s request states that its proposed changes will not alter its authority to enter into black start agreements but rather adjusts “cost allocation rules for costs the CAISO plans to incur to procure additional black start capability.”¹⁸³ The Commission found the proposed tariff revisions to be just and reasonable.¹⁸⁴ In particular, the Commission found that the revisions improved the readability and clarity of the tariff as it relates to the Reliability Standard, and helps distinguish black start capability from other ancillary services, as it is not procured in CAISO’s day-ahead and real time markets.¹⁸⁵ As requested, the Commission accepted the tariff revisions effective November 1, 2017.¹⁸⁶

174. *Cal. Pub. Utils. Comm’n*, 854 F.3d at 1146.

175. 121 F.E.R.C. ¶ 61,067 at PP 36-42.

176. *Id.* at PP 17-19; 136 F.E.R.C. ¶ 61,036 at P 40.

177. *San Diego Gas & Elec. Co. v. Sellers of Ancillary Servs.*, 121 F.E.R.C. ¶ 61,067 (2007), *order on reh’g*, 125 F.E.R.C. ¶ 61,214 (2008), *order accepting compliance filings*, 136 F.E.R.C. ¶ 61,036 (2011), *reh’g denied*, 138 F.E.R.C. ¶ 61,092 (2012).

178. 136 F.E.R.C. ¶ 61,036 at P 59.

179. *Cal. Indep. Sys. Operator Corp.*, 161 F.E.R.C. ¶ 61,116 at P 1 (2017).

180. *Id.* at P 2.

181. *Id.* at PP 2, 4.

182. Letter from CAISO Director of Federal Regulatory Affairs Andrew Ulmer to FERC Secretary Kimberly D. Bose (Aug. 3, 2017).

183. *Id.* at 1.

184. *Id.* at 6.

185. *Id.* at 13.

186. 161 F.E.R.C. ¶ 61,116 at P 1.

On May 12, 2017, the U.S. Court of Appeals for the Ninth Circuit affirmed a lower court ruling, which held that the “filed rate doctrine” barred plaintiffs’ Racketeer Influenced and Corrupt Organization Act (RICO) claim against J.P. Morgan Ventures Energy Corporation (JPMVEC) for alleged market manipulation.¹⁸⁷ Those RICO charges stemmed from a FERC investigation into JPMVEC’s bidding practices wherein JPMVEC admitted to wholesale market manipulation and disgorged \$124 million in unjust projects, as well as fines into the U.S. Treasury.¹⁸⁸ In response to the findings of this investigation, plaintiffs brought a class action lawsuit against JPMVEC in federal district court under RICO for the manipulation.¹⁸⁹ The complaint alleged that, in its enforcement action, FERC rejected and disapproved the JPMVEC wholesale electricity rates in question.¹⁹⁰ JPMVEC moved to dismiss the RICO complaint under Federal Rules of Civil Procedure rule 12(b)(6) on grounds that the “filed rate” doctrine barred the action, and the district court granted the 12(b)(6) motion.¹⁹¹ The district court appealed to a Ninth Circuit case that stands for the principle that the doctrine does not apply to bar RICO claims arising from alleged price manipulation, because the rate-setting agency in that case, the U.S. Department of Agriculture (USDA), had explicitly rejected the relevant rates as resulting from fraud.¹⁹² The Ninth Circuit rejected the *Woolsey* plaintiffs’ argument because *Carlin* involved a rate-setting agency, the USDA, which had statutory power to recalculate – and thus retroactively alter – prior rates; the court ruled that FERC had no such power.¹⁹³

G. Bonneville Power Administration

On May 19, 2017, the U.S. Court of Appeals for the D.C. Circuit found that FERC has the authority to order a publicly-owned, non-jurisdictional utility, such as Bonneville Power Administration (BPA), to return funds that it received due to an error by the Commission.¹⁹⁴ In so doing, the court also chose not to disturb FERC’s original finding that a generator must have a rate on file if it is providing reactive power service—even if it is supplying that service for free.¹⁹⁵ Specifically, the court rejected the Commission’s conclusion that it lacked authority to order recoupment of funds paid by Chehalis Power Generating, L.P. (whose claim is being pursued by its former parent company TNA Merchant Projects, Inc.) to BPA, a non-jurisdictional public utility, because FERC’s refund authority does not extend to public utilities.¹⁹⁶ Rather, the court found that the case “does not

187. *Woolsey v. J.P. Morgan Ventures Energy Corp.*, 691 Fed. App’x 308, 2017 WL 2056981 (S.D. Cal. May 12, 2017).

188. *Id.* at *1.

189. *Id.* at *2.

190. *Id.* at *3.

191. *Id.* at *1.

192. *Woolsey*, 2017 WL 2056981 at **5-8; *Carlin v. DairyAmerica, Inc.*, 705 F.3d 856, 873, 879 (9th Cir. 2013).

193. *Id.* at **1-2.

194. *TNA Merch. Projects, Inc. v. FERC*, 857 F.3d 354, 355, 359 (D.C. Cir. 2017).

195. *Id.* at 362.

196. *Id.* at 356-57.

involve a request for a refund under section 205 [of the FPA]” but instead “concerns recoupment, which is an entirely distinct remedy from a refund.”¹⁹⁷ The court concluded that “sections 201(f) and 205, together, do not limit FERC’s authority to order a recoupment where a non-jurisdictional entity improperly received a refund.”¹⁹⁸ Relying on its prior decision in *Xcel Energy Services, Inc. v. FERC*, the court reiterated that “section 309 affords the agency broad authority to ‘remedy its errors’ and correct unjust situations.”¹⁹⁹ Additionally, the court found that *Black Oak Energy, LLC v. FERC* “provides strong support for the position that FERC retained the authority to amend its decision to require Chehalis to refund a portion of its rates and order recoupment.”²⁰⁰ The court found that FERC “retained authority under section 309 to order [Bonneville] to return the funds when the agency acknowledged that its initial order was mistaken.”²⁰¹ The court remanded the case to FERC for further action.²⁰²

H. Southeast

The D.C. Circuit affirmed FERC’s interpretation of Florida Power & Light Company’s (Florida Power) OATT and a related transmission service agreement in a case involving the appropriate level of refund owed by Florida Power to its wholesale transmission customer, Seminole Electric Cooperative, Inc. (Seminole), for energy imbalance service overcharges.²⁰³ First, the court found that FERC correctly interpreted language in Seminole’s transmission service agreement with Florida Power to require Seminole to bring any bill challenge within twenty-four months of receiving the bill, and, accordingly, FERC properly restricted refunds to a period going back twenty-four months from when Seminole first complained about Florida Power’s overcharges.²⁰⁴ Second, the court upheld FERC’s finding that, while Florida Power’s OATT divided energy imbalance charges into three “tiers” based on the size of the imbalance, Florida Power was entitled by the OATT to calculate Seminole’s imbalance charge by applying the rate of the highest applicable imbalance tier to Seminole’s entire imbalance.²⁰⁵ In other words, calculation of the energy imbalance charges did not work like tax brackets under the U.S. tax code—an analogy raised by Seminole, but rejected by the court.²⁰⁶

III. LOUISIANA PUBLIC SERVICE COMMISSION

On August 8, 2017, the D.C. Circuit denied the petition for review brought by the Louisiana Public Service Commission (LaPSC) challenging the Commission’s decision to allow the use of state retail depreciation rates in calculating each

197. *Id.* at 359.

198. *Id.* (emphasis omitted).

199. *TNA Merch. Projects*, 857 F.3d at 359 (citing *Xcel Energy Services, Inc. v. FERC*, 815 F.3d 947, 956 (D.C. Cir. 2016)).

200. *Id.* at 361-62. See *Black Oak Energy, LLC v. FERC*, 725 F.3d 230 (D.C. Cir. 2013).

201. *TNA Merch. Projects*, 857 F.3d at 362.

202. *Id.* at 356.

203. *Seminole Elec. Coop. v. FERC*, 861 F.3d 230 (D.C. Cir. 2017).

204. *Id.* at 234-36.

205. *Id.* at 236-38.

206. *Id.* at 236-37.

Entergy Operating Company's annual production costs as part of the "bandwidth remedy" under the Entergy System Agreement's rough production cost equalization formula.²⁰⁷ The LaPSC primarily contended that FERC failed to confront evidence that the use of state-determined depreciation rates was unduly discriminatory and harmful to Louisiana's ratepayers.²⁰⁸ The court disagreed, finding that the LaPSC failed to support its claim because the inconsistencies in state retail depreciation rates was not evidence of state manipulation to subvert the bandwidth formula for the state's own benefit, but was based on "legitimate ratemaking considerations."²⁰⁹ The LaPSC also asserted that FERC failed to explain adequately why it did not require the use of FERC's accounting rules to set the depreciation rates used in the bandwidth formula.²¹⁰ The court rejected this view, finding that "the bandwidth formula [did] not . . . implicate FERC's wholesale ratemaking activities," and because of the unique nature of the bandwidth formula, it "did not require the use of FERC's own depreciation standards."²¹¹ Finally, the LaPSC argued that by allowing state regulators to establish the depreciation component in the bandwidth formula "FERC unlawfully subdelegated its exclusive jurisdiction over wholesale rates."²¹² The court concluded that there was "no unlawful subdelegation because FERC has exercised, and intends to continue to exercise, its section 206 review authority [of state depreciation rates]."²¹³

IV. MERGERS AND ACQUISITIONS

In *Orangeburg v. FERC*, the D.C. Circuit partially vacated and remanded FERC orders approving a Joint Dispatch Agreement (JDA) that governed interstate dispatch of power from the generation systems of Duke Energy Carolinas (Duke) and Progress Energy Carolinas, Inc. (Progress), which the court determined extended disparate treatment to interstate whole ratepayers.²¹⁴ The JDA distinguished between native load and non-native load wholesale customers, "providing that only the former would be entitled to the most reliable and lowest cost power."²¹⁵ The City of Orangeburg, South Carolina ("Orangeburg") challenged FERC's approval of the JDA, arguing that the JDA, in conjunction with actions of the North Carolina Utilities Commission (NCUC), permitted Duke/Progress to engage in undue discrimination between wholesale customers.²¹⁶ Orangeburg contended that the NCUC effectively decided which wholesale customers could be considered native load under the JDA through its practice of partially disallowing retail rate recovery of costs associated with serving wholesale customers that the NCUC deemed non-native load.²¹⁷ The D.C. Circuit found that

207. La. Pub. Serv. Comm'n v. FERC, 860 F.3d 691 (D.C. Cir. 2017).

208. *Id.* at 694.

209. *Id.* at 695.

210. *Id.*

211. *Id.*

212. *Id.* at 695-96.

213. *Id.* at 696.

214. *Orangeburg v. FERC*, 862 F.3d 1071 (D.C. Cir. 2017).

215. *Id.* at 1076.

216. *Id.* at 1082, 1085.

217. *Id.* at 1076-77, 1084-85.

FERC had not adequately supported its approval of the JDA, which “established disparate treatment between native-load and non-native-load wholesale customers,” but instead had justified disparate treatment by pointing to language in its Order No. 2000, recognizing the authority of state commissions in non-retail choice states to require utilities to sell their lowest-cost power to native load.²¹⁸ The court concluded that the relevant language from Order No. 2000 “cannot, without more explanation, be extended to justify disparate treatment of *interstate wholesale* ratepayers.”²¹⁹

V. PURPA

On May 17, 2017, the U.S. District Court for the District of Columbia dismissed a lawsuit brought by qualifying facility owners/operators against FERC and two electric cooperatives seeking to enforce requirements under the Public Utility Regulatory Policies Act of 1978 (PURPA).²²⁰ The plaintiffs alleged that the defendant electric cooperatives violated FERC PURPA regulations in calculating their avoided cost.²²¹ The plaintiffs also alleged that FERC failed to enforce its own PURPA regulations against defendant electric cooperatives.²²² In its decision, the court concluded that it lacked personal jurisdiction over the two electric cooperative defendants, both of which were based in Iowa and lacked any connection with the forum that would satisfy the District of Columbia’s long-arm statute.²²³ Construing plaintiffs’ suit against FERC as an action under section 702 of the Administrative Procedure Act (APA), the court noted that judicial review is not available under section 702 of the APA for actions “committed to agency discretion by law.”²²⁴ A decision not to initiate an enforcement action, the court explained, is presumed to be immune from judicial review under APA section 701(a)(2), and, applying criteria described in *Baltimore Gas & Electric Co. v. FERC*, the court found that plaintiffs had not overcome the presumption of non-reviewability.²²⁵ Because “the ban on judicial review of actions ‘committed to agency discretion by law’ is jurisdictional,” the court dismissed the suit against FERC for lack of subject matter jurisdiction.²²⁶

On April 25, 2017, the D.C. Circuit ruled on consolidated petitions for review of FERC orders stemming from a wind farm and utility who had entered into a power-purchase agreement but who disagreed as to whether the utility must purchase all of the power delivered to it, even if the amount of power delivered is

218. *Id.* at 1085; *Duke Energy Corp. & Progress Energy, Inc.*, 139 F.E.R.C. ¶ 61,193 at P 45 (2012) (quoting *Regional Transmission Organizations*, Order No. 2000, F.E.R.C. STATS. & REGS. ¶ 31,089 (1999), *order on reh’g*, Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 31,092 (2000), *aff’d sub nom.* Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001)).

219. 862 F.3d at 1085 (emphasis in original).

220. *Swecker v. Midland Power Coop.*, 253 F. Supp. 3d 274 (D.D.C. 2017).

221. *Id.*

222. *Id.*

223. *Id.*

224. 5 U.S.C. § 702 (1996); *Swecker*, 253 F. Supp. 3d at 279.

225. *Id.* at 279-80.

226. *Id.* at 279 (quoting *Balt. Gas & Elec.*, 252 F.3d at 458-59) (internal quotes and alterations omitted).

more than was contracted for, and delivered without being scheduled.²²⁷ The utility asked the D.C. Circuit to review FERC's findings that, under the power-purchase agreement, the utility must accept all of the wind farm's "entire net output delivered to Portland," and the wind farm sought review of FERC's finding that the utility does not have to purchase the power using the wind farm's dynamic scheduling system.²²⁸ In its finding, the court dismissed the utility's request for rehearing of FERC's order, which required the utility to purchase the wind farm's entire net output, and held that it lacked jurisdiction under PURPA judicial review and enforcement provisions since FERC has exclusive authority over PURPA enforcement actions that involve interstate transmission or wholesale generation.²²⁹ The court also denied, on the merits, the wind farm's FPA claims seeking to overturn FERC's findings that the utility does not have an obligation to utilize dynamic scheduling technology under the power purchase agreement, because, the court reasoned, the wind farm is not a transmission customer and has no basis for its claims.²³⁰

VI. MISCELLANEOUS

On January 30, 2017, the U.S. District Court for the District of Columbia issued a Memorandum Opinion and Order on whether City Power Marketing was entitled to conduct discovery prior to the adjudication of a summary judgment motion concerning FERC having found City Power to have violated FERC's Anti-Manipulation Rule and Market Behavior Rule.²³¹ The court granted City Power Marketing's Rule 56(d) motion for discovery as to the market manipulation claims and market behavior claims, but denied City Power Marketing's motion with respect to FERC's jurisdiction.²³² In so doing, the court first ruled that City Power's declarations to the court satisfied the *Convertino* criteria with respect to the market manipulation and market behavior claims, and that City Power was entitled to discovery.²³³ The court noted that City Power had not had a "full opportunity" for discovery during FERC's administrative proceeding and that the facts they intend to discover were not sought out by FERC during its discovery process.²³⁴ Further, the court rejected City Power's request for discovery with respect to FERC's jurisdiction, stating the issue had been concluded in a prior opinion and, thus, there was nothing further to discover on the subject.²³⁵

In a pair of cases decided within two weeks of one another, U.S. District Courts in Maine and California took up challenges in those states related to, among

227. *PáTu Wind Farm, LLC v. Portland General Elec. Co.*, 150 F.E.R.C. ¶ 61,032 (2015).

228. *PáTu Wind Farm, LLC*, 150 F.E.R.C. ¶ 61,032 at P 49.

229. *Id.* at P 3. See 16 U.S.C. § 824a-3(h); Fed. Power Act § 313; 16 U.S.C.A. § 825l(b).

230. *Portland General Elec. Co. v. FERC*, 854 F.3d 692 (D.C. Cir. 2017).

231. *FERC v. City Power Mktg., LLC*, 235 F. Supp. 3d 152 (D.D.C. Jan. 30, 2017); 18 C.F.R. § 1c.2 (2016); 18 C.F.R. § 35.41(b) (2016).

232. *Id.*

233. *Id.* at 155. See *Convertino v. Dep't of Justice*, 684 F.3d 93, 99 (D.C. Cir. 2012)). Specifically, the declarant must outline the facts they intend to discover and show that those facts are necessary to litigation, were unable to be produced without discovery, and are, in fact, discoverable.

234. *Id.* at 156.

235. *Id.*

other things, the meaning of “de novo” review when hearing FERC appeals.²³⁶ This is a particularly interesting question, given the highly technical nature of FERC decisions.

In January 2017, the U.S. District Court for the District of Maine became one in a string of district courts to reject FERC’s position that actions to enforce civil penalty assessment orders should be confined to the administrative record, without discovery and other features of the Federal Rules of Civil Procedure (FRCP).²³⁷ In that case, the court reviewed FERC orders from August 2013 assessing civil penalties against Dr. Richard Silkman and his company Competitive Energy Services (CES) for violation of section 222 of the FPA, and the Commission’s Anti-Manipulation Rule by defrauding ISO-NE in the implementation of its Day-Ahead Load Response Program (DALRP).²³⁸ The FERC alleged that Dr. Silkman convinced a paper company in Maine to inflate artificially its baseline energy consumption by temporarily reducing use of an on-site generator.²³⁹ Under section 222, if penalties are not paid in sixty days, the Commission may seek to enforce in U.S. District Court, and the court “shall have authority to review de novo the law and the facts involved.”²⁴⁰ In its appeal, FERC argued that the language in the FPA referring to “de novo review” gave the court discretion as to what procedures to apply.²⁴¹ Given the lengthy administrative proceeding below, FERC contended that the court’s review of an assessment order should “begin . . . and end . . . with the Assessment Orders, supplemented as necessary by the administrative record.”²⁴² Respondents countered that *de novo* review means both parties should be permitted to develop evidence through the usual tools of discovery, including evidence internal to the enforcement investigation itself, and evidence should not be limited to the administrative record.²⁴³ The court ruled in favor of respondents, holding that the FRCP would apply to the action, including discovery.²⁴⁴ Notably, the court made clear that its holding should not be interpreted as a “grand pronouncement about the scope of de novo review under section 823b(d)(3).”²⁴⁵

On March 28, 2017, the U.S. District Court for the Eastern District of California issued an order denying FERC’s Motion to Affirm Civil Penalties (Motion), which assessed penalties and disgorgements against Barclays Bank PLC and four traders (Barclays) for alleged violations of anti-manipulation provisions of the FPA and FERC’s Anti-Manipulation Rule, 18 C.F.R. pt. 1(c)(1).²⁴⁶ The central question before the court was “whether or not the [c]ourt should permit the parties to conduct

236. FERC v. Silkman, 233 F. Supp. 3d 201 (D. Me. 2017); FERC v. Barclays Bank PLC, 247 F. Supp. 3d 1118 (E.D. Cal. 2017).

237. See generally *Silkman*.

238. *Id.* at 207.

239. *Id.*

240. *Id.* at 219.

241. *Id.* at 204.

242. *Silkman*, 233 F. Supp. 3d at 210.

243. *Id.* at 210.

244. *Id.*

245. *Id.* at 204.

246. See generally *Barclays*.

discovery under the Federal Rules of Civil Procedure.”²⁴⁷ In denying FERC’s Motion, the court ruled that *de novo* review here did not restrict the evidence to the administrative record; rather it permits the parties to full discovery pursuant to those rules.²⁴⁸

As discussed below, in a pair of cases decided within two weeks of one another, U.S. District Courts in New York and Illinois took up challenges in those states related to out-of-market “zero emissions credits” payments made to qualifying generators that many believe were intended to subsidize the nuclear industry.²⁴⁹

First, on July 25, 2017, the U.S. District Court for the Southern District of New York dismissed a challenge brought by a collection of independent power producers and generator trade groups to a component of the NYPSC’s “Clean Energy Standard.”²⁵⁰ Plaintiffs argued that the portion of New York’s Clean Energy Standard that offers environmental attribute payments—known as “zero-emissions credits” (ZECs)—to qualifying nuclear resources was both field and conflict preempted under the FPA, and violates the dormant Commerce Clause.²⁵¹ Among other things, the plaintiffs alleged that the ZEC program was preempted by the FPA because receipt of the subsidies was impermissibly “tethered” to FERC-jurisdictional wholesale market auctions to those in *Hughes v. Talen Energy Marketing, LLC*, and that the program would interfere with FERC reliance on competitive markets to set wholesale energy prices.²⁵² Plaintiffs also asserted that the ZEC program violated the dormant Commerce Clause by facially discriminating against out-of-state energy producers and by unduly burdening interstate commerce by distorting market pricing and incentives.²⁵³ The court disagreed, and found that even if the plaintiffs’ preemption claims were properly before the court, they still would fail because “[b]y establishing a program that does not condition or tether ZEC payments to wholesale auction participation, New York has successfully threaded the needle left by *Hughes* that allows States to adopt innovative programs to encourage the production of clean energy.”²⁵⁴ The court also rejected the contention that the program conflicts with FERC’s reliance on markets, finding that “FERC has approved state programs with ‘renewable portfolio mandates and greenhouse reduction goals,’” and that “[t]he ZEC program does not thwart the goal of an efficient energy market; rather, it encourages through financial incentives the production of clean energy.”²⁵⁵ Finally, the court rejected the plaintiffs’ dormant Commerce Clause claims, as the injuries were outside of the zone of interests protected by the dormant Commerce Clause.²⁵⁶ The court held that even if the plaintiffs had a cause of action under the dormant

247. *Id.* at 1121.

248. *Id.*

249. Memorandum Opinion & Order, *Coalition for Competitive Elec. v. Zibelman*, Docket No. 16-CV-8164 (S.D.N.Y. July 25, 2017).

250. *Id.* at 2.

251. *Id.*

252. *Id.* at 17-18.

253. *Id.* at 2.

254. *Zibelman* at 29.

255. *Id.* at 32 (quoting *Pac. Gas & Elec. Co.*, 123 F.E.R.C. ¶ 61,067 at P 34 (2008)).

256. *Id.* at 42.

Commerce Clause, their claims would still fail because New York was acting as a market participant, not as a regulator, when it created ZECs.²⁵⁷

On July 14, 2017, the U.S. District Court for the Northern District of Illinois dismissed a pair of complaints challenging Illinois's "Future Energy Jobs Act," which created a new commodity—the "Zero Emission Credit" (ZEC)—intended to compensate qualifying nuclear facilities for the environmental attributes of their power production.²⁵⁸ Plaintiffs challenged the Illinois ZEC program on grounds that it was preempted by the FPA and that the program burdened interstate commerce in violation of the dormant Commerce Clause.²⁵⁹ Plaintiffs argued that the ZEC payments intruded on FERC's exclusive jurisdiction under the FPA, because those payments would "effectively replac[e] the auction clearing price received by [ZEC recipients] with the alternative, higher price preferred by the Illinois General Assembly," and would distort the outcomes in FERC's wholesale electricity markets.²⁶⁰ The court dismissed the claims, holding that "the [FPA] does not authorize a private cause of action for injunctive relief against the defendants," and that "[t]he declaration sought by plaintiffs *would* require a court to draw some lines, to give the state direction on how not to interfere with wholesale rates while acting within its undisputed authority to regulate, and once a court enters that arena, it treads on FERC's exclusive expertise."²⁶¹ Even if plaintiffs did have a preemption cause of action, the court held that the ZEC program nonetheless did not intrude into FERC's exclusive field because it "falls within Illinois's reserved authority over generation facilities," and that "Illinois has sufficiently separated ZECs from wholesale transactions such that the [FPA] does not preempt the state program under principles of field preemption."²⁶² Finally, the district court dismissed the dormant Commerce Clause challenges, holding "[t]he alleged harm to out-of-state power generators who will be competing in auctions against subsidized participants is not clearly excessive when balanced against" the states' interests in environmental protection.²⁶³

On October 4, 2017, the Commission issued two separate orders clarifying its jurisdiction under sections 203 and 205 of the FPA related to certain project development activities. First, in *Ad Hoc Renewable Energy Financing Group*, FERC granted a petition for declaratory order and confirmed that certain tax equity interests in public utilities do not constitute "voting securities" for purposes of FPA section 203, and, therefore, the issuance or transfer of such interests does not require prior FERC approval.²⁶⁴ In its holding, FERC found that "the tax equity interests in public utilities or public utility holding companies identified in *AES Creative Resources* do not constitute voting securities for purposes of FPA section

257. *Id.*

258. *Vill. of Old Mill Creek v. Star*, Docket No. 17-CV-1163 (N.D. Ill. Feb. 14, 2017); *Elec. Power Supply Ass'n v. Star*, Docket No. 17-CV-1164 (N.D. Ill. Feb. 14, 2017) [hereinafter *EPSA Complaint*]; S.B. 2814, 99th Gen. Assemb. (Ill. 2016).

259. *Old Mill Creek*, slip op. at 5.

260. *Id.* at 4.

261. *Id.* at 9 (emphasis added).

262. *Id.* at 14.

263. *Id.* at 17.

264. *Ad Hoc Renewable Energy Financing Group*, 161 F.E.R.C. ¶ 61,010 at P 1 (2017).

203.²⁶⁵ As a result, the issuance or transfer of such interests does not constitute a transfer of control requiring prior authorization from FERC.²⁶⁶ The FERC also confirmed that the acquisition of such interests by a holding company qualifies for FERC's blanket authorization under section 33.1.(c)(2)(i).²⁶⁷ Separately, in *ALLETE, Inc.*, FERC disclaimed jurisdiction under FPA section 205 over certain pre-construction activities, and thereby found that ALLETE, Inc. (Allete) did not need to file with FERC certain pre-construction agreements.²⁶⁸ Allete and Manitoba Hydro and its subsidiary had entered into a series of pre-construction agreements for the design, construction, and operation of the Great Northern Transmission Line, which was not yet in service.²⁶⁹ Specifically, the agreements addressed preliminary scoping, study, pre-construction activities and cost-sharing between the parties.²⁷⁰ Allete filed the agreements with FERC "out of an abundance of caution," but requested that FERC determine that such agreements are not FPA jurisdictional to the extent they do not affect or relate to rates or services.²⁷¹ The Commission dismissed Allete's filing for lack of jurisdiction over the agreements because they failed to exceed FERC's "significant" threshold.²⁷² However, in its order, FERC specifically retained the authority to request such agreements to be filed in the future to the extent the reasonableness of costs incurred under the agreements may impact recovery in jurisdictional rates.²⁷³

265. *Id.* at P 17.

266. *Id.*

267. *Id.*

268. *ALLETE, Inc.*, 161 F.E.R.C. ¶ 61,013 (2017).

269. *Id.* at P 5.

270. *Id.* at P 8.

271. *Id.*

272. *Id.* at P 9.

273. *Id.* at P 14.

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